Boston Edison
A BEC ENERGY COMPANY
800 Boylston Street
Boston, Massachusetts 02199

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

(617) 424-2463

November 16, 1998
BECo Ltr. 2-98-148

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Docket No. 50-293
License No. DPR-35

Dear Sir:

In accordance with 10CFR140.21 and the 1975 amendments to the Price Anderson Act (Public Law 94-97), Boston Edison is submitting the following:

1. Boston Edison Company Annual Report for 1997

2. Boston Edison Company Form 10-Q for the quarter ended September 30, 1998, as filed with the Securities and Exchange Commission

3. Cash Flow Forecast for the Year 1999

4. Narrative Statement of Curtailment of Capital Expenditures

Very truly yours,

Enclosures

cc: Mr. Alan B. Wang, Project Manager
Project Directorate I-1
Office of Nuclear Reactor Regulation
Mail Stop: 14B2
U. S. Nuclear Regulatory Commission
1 White Flint North
11555 Rockville Pike
Rockville, MD 20852

Regional Administrator, Region 1
U. S. Nuclear Regulatory Commission
475 Allendale Roade
King of Prussia, PA 19406

Mr. Ira P. Dintz
Insurance Indemnity Specialist
Office of Nuclear Reactor Regulation
Mail Stop: 10H5
U. S. Nuclear Regulatory Commission
1 White Flint North
11555 Rockville Pike
Rockville, MD 20852

Senior Resident Inspector
Pilgrim Nuclear Power Station

M004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[x] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 1998

or

[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from __________ to __________

Commission file number 1-2301

BOSTON EDISON COMPANY
(Exact name of registrant as specified in its charter)

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

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

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 ____

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

Class	Outstanding at September 30, 1998
Common Stock, $1 par value	100 shares

Part I - Financial Information

Item 1. Financial Statements

Boston Edison Company
Consolidated Statements of Income
(Unaudited)
(in thousands)

	Three Months Ended September 30, 1998	Three Months Ended September 30, 1997	Nine Months Ended September 30, 1998	Nine Months Ended September 30, 1997
Operating revenues	$476,226	$520,414	$1,256,767	$1,370,104
Operating expenses:				
Energy supply	191,197	202,991	522,262	607,150
Operations and maintenance	85,902	103,569	269,099	301,321
Depreciation and amortization	22,329	29,089	69,453	71,273
Demand side management and renewable energy programs	10,102	7,463	27,144	21,560
Taxes - property and other	15,312	24,808	62,684	76,963
Income taxes	50,578	45,821	90,816	78,395
Total operating expenses	375,420	413,741	1,041,458	1,156,662
Operating income	100,806	106,673	215,309	213,442
Other income (expense), net	799	1,697	(4,318)	3,508
Operating and other income	101,605	108,370	210,991	216,950
Interest charges:				
Long-term debt	19,457	23,049	63,489	69,436
Other	66	4,174	7,786	12,129
Allowance for borrowed funds used during construction	(410)	(271)	(975)	(949)
Total interest charges	19,113	26,952	70,300	80,616
Net income	$ 82,492	$ 81,418	$ 140,691	$ 136,334

Consolidated Statements of Retained Earnings
(Unaudited)
(in thousands)

	Three Months 1998	Three Months 1997	Nine Months 1998	Nine Months 1997
Balance at the beginning of the period	$262,116	$290,832	$ 328,802	$ 292,191
Net income	82,492	81,418	140,691	136,334
Dividends declared:				
Dividends to common shareholders	0	(22,802)	(22,802)	(68,406)
Dividends to BEC Energy	(23,000)	0	(116,000)	0
Preferred stock	(1,486)	(2,919)	(7,275)	(10,230)
Transfer of BETG to BEC Energy	0	0	(2,980)	0
Subtotal	320,122	346,529	320,436	349,889
Provision for preferred stock redemption and issuance costs	(7,459)	(157)	(7,773)	(3,517)
Balance at the end of the period	$312,663	$346,372	$ 312,663	$ 346,372

Per share data is not relevant because Boston Edison Company's common stock is wholly owned by BEC Energy.

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

Boston Edison Company
Consolidated Balance Sheets
(Unaudited)
(in thousands)

	September 30, 1998	December 31, 1997
Assets		
Utility plant in service, at original cost	$2,689,406	$4,451,134
Less: accumulated depreciation	903,432	1,712,903
	1,785,974	2,738,231
Generation-related regulatory asset, net	374,095	0
Nuclear fuel, net	60,049	67,935
Construction work in progress	43,812	33,292
Net utility plant	2,263,930	2,839,458
Non-utility property	0	14,669
Nuclear decommissioning trust	168,990	151,634
Equity investments	20,726	35,455
Other investments	9,063	7,107
Current assets:		
Cash and cash equivalents	138,734	4,140
Accounts receivable	256,560	207,093
Accrued unbilled revenues	21,736	30,048
Fuel, materials and supplies, at average cost	16,175	60,834
Prepaid expenses and other	67,276	31,283
Total current assets	500,481	333,398
Other regulatory assets:		
Power contracts	62,534	71,445
Income taxes, net	51,876	51,096
Redemption premiums	24,016	27,019
Postretirement benefits costs	21,804	22,441
Other	1,045	23,369
Total regulatory assets	161,275	195,370
Other deferred debits	28,201	45,256
Total assets	$3,152,666	$3,622,347

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

Boston Edison Company
Consolidated Balance Sheets
(Unaudited)
(in thousands)

	September 30, 1998	December 31, 1997
Capitalization and Liabilities		
Common stock equity:		
Common stock and premium	$ 742,905	$ 744,652
Retained earnings	312,663	328,802
Total common stock equity	1,055,568	1,073,454
Cumulative preferred stock:		
Nonmandatory redeemable series	43,000	83,000
Mandatory redeemable series	48,980	78,093
Total preferred stock	91,980	161,093
Long-term debt	955,638	1,057,076
Total capitalization	2,103,186	2,291,623
Current liabilities:		
Long-term debt/preferred stock due within one year	1,067	102,667
Notes payable	0	137,013
Accounts payable	98,759	87,015
Transition contract payable	31,223	0
Taxes payable	33,018	(630)
Accrued interest	11,675	24,289
Dividends payable	23,993	24,748
Other	153,941	128,691
Total current liabilities	353,676	503,793
Deferred credits:		
Accumulated deferred income taxes	350,569	485,738
Accumulated deferred investment tax credits	46,714	60,736
Nuclear decommissioning liability	172,423	155,182
Power contracts	62,534	71,445
Other	63,564	53,830
Total deferred credits	695,804	826,931
Commitments and contingencies		
Total capitalization and liabilities	$3,152,666	$3,622,347

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

Boston Edison Company
Consolidated Statements of Cash Flows
(Unaudited)
(in thousands)

	Nine Months Ended September 30, 1998	1997
Operating activities:		
Net income	$ 140,691	$ 136,334
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	178,051	170,395
Deferred income taxes and investment tax credits	(149,710)	(21,707)
Allowance for borrowed funds used during construction	(975)	(949)
Net changes in:		
Accounts receivable and accrued unbilled revenues	(28,305)	3,704
Fuel, materials and supplies	28,667	(172)
Transition contract and other accounts payable	48,926	(45,242)
Other current assets and liabilities	9,423	27,841
Other, net	3,801	(4,590)
Net cash provided by operating activities	230,569	265,614
Investing activities:		
Plant expenditures (excluding AFUDC)	(66,998)	(90,900)
Proceeds from sale of fossil assets	533,633	0
Nuclear fuel expenditures	(11,141)	(2,811)
Investments	(29,639)	(28,711)
Net cash provided by (used in) investing activities	425,855	(122,422)
Financing activities:		
Issuances:		
Common stock	0	144
Long-term debt	0	100,000
Redemptions:		
Preferred stock	(71 519)	(44,000)
Long-term debt	(201,600)	(101,600)
Net change in notes payable	(101,878)	(17,164)
Dividends paid	(146,833)	(79,234)
Net cash used in financing activities	(521,830)	(141,854)
Net increase in cash and cash equivalents	134,594	1,338
Cash and cash equivalents at beginning of year	4,140	5,651
Cash and cash equivalents at end of period	$ 138,734	$ 6,989
Supplemental disclosures of cash flow information:		
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 79,549	$ 87,916
Income taxes	$ 182,200	$ 59,289

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

Notes to Unaudited Consolidated Financial Statements

A) Basis of Presentation

Boston Edison Company (Boston Edison) received final approval of its reorganization plan to form a holding company structure from the Securities and Exchange Commission on May 20, 1998. Effective May 20 the holding company, BEC Energy (BEC), was formed with Boston Edison as a wholly owned subsidiary of BEC. Under the new holding company structure the owners of Boston Edison's common stock became BEC common shareholders. Existing debt and preferred stock of Boston Edison remained obligations of the regulated utility business. Effective June 25, 1998, Boston Energy Technology Group (BETG) ceased being a subsidiary of Boston Edison and became a wholly owned subsidiary of BEC. The accompanying consolidated financial statements reflect the results of operations and cash flows of Boston Edison prior to the reorganization. BETG is excluded from the results of operations and cash flows of Boston Edison in the third quarter of 1998. The consolidated balance sheet at December 31, 1997 reflects the financial position of Boston Edison which also included BETG. BETG is excluded from the consolidated balance sheet of Boston Edison at September 30, 1998.

The accompanying unaudited consolidated financial statements should be read in conjunction with the Boston Edison 1997 Annual Report on Form 10-K and Forms 10-Q for the periods ended March 31, 1998 and June 30, 1998. The financial information presented as of September 30 has been prepared from Boston Edison's books and records without audit by independent accountants. Financial information as of December 31 has been derived from the audited financial statements of Boston Edison, but does not include all disclosures required by generally accepted accounting principles (GAAP). In the opinion of management, all adjustments (which are of a normal recurring nature) necessary for a fair presentation of the financial information for the periods indicated have been included. Certain reclassifications have been made to the prior year data to conform with the current presentation.

Under the Boston Edison restructuring settlement agreement, which was approved by the Massachusetts Department of Telecommunications and Energy (DTE), approximately 75% of the net assets of Pilgrim Nuclear Power Station are recoverable through a non-bypassable transition charge of the utility's distribution business. The distribution business continues to be subject to rate-regulation. The remaining 25% is collected under Pilgrim's wholesale power contracts with other utilities and municipalities. Consistent with the guidance from accounting authoritative bodies regarding any impaired portion of utility plant assets identified for recovery in a legislative/rate order, the 1998 consolidated balance sheet reflects a reclassification of the Pilgrim net assets recoverable through the transition charge from utility plant to regulatory asset. This Pilgrim regulatory asset, included in the generation-related regulatory asset on the consolidated balance sheet at September 30, 1998, continues to be grouped with utility plant for financial statement presentation. Refer to Note C of Item 8 in the Boston Edison 1997 Annual Report on Form 10-K for more information on the accounting implications of the electric utility industry restructuring and the utility's related settlement agreement.

Finalization of the sale of Boston Edison's fossil generating assets to Sithe Energies took place on May 15, 1998. Boston Edison received proceeds from the sale of $655 million, including $121 million for a six-month transitional power purchase contract. The amount received above net book value on the sale of these assets will be returned to Boston Edison's customers over the settlement period. That amount is partially offset by certain costs recoverable through the transition charge due to the support of standard offer service provided by Boston Edison's fossil generating assets prior to the fossil divestiture. The net deferred gain is included as a reduction to the generation-related regulatory asset on the consolidated balance sheet at September 30, 1998. In addition, Boston Edison received $19 million from Sithe for inventory and other closing adjustments.

Under the terms of Boston Edison's settlement agreement, generation and purchased power costs are recovered from customers. The settlement agreement allows for the deferral of the difference between these costs and the amounts billed to customers with a return for future recovery. The net undercollection from the settlement recovery mechanisms at September 30, 1998 was more than offset by an overrecovery of approximately $36 million from the fuel and purchased power clause and is included in other regulatory assets on the consolidated balance sheet. The fuel and purchased power clause ceased on March 1, 1998. The inclusion of the over recovered fuel and purchased power clause costs as an offset to the settlement recovery mechanisms is consistent with Boston Edison's proposal made to the DTE. Generation and purchased power costs recoverable under the settlement agreement have been separately reflected as energy supply expenses on the consolidated statements of income. These costs include retail generation-related depreciation and amortization, decommissioning and other operating costs recovered through the transition charge. The corresponding 1997 expenses have been reclassified for comparability.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

The results of operations for the three and nine-month periods ended September 30, 1998 and 1997 are not indicative of the results which may be expected for an entire year. Kilowatt-hour sales and revenues are typically higher in the winter and summer than in the spring and fall as sales tend to vary with weather conditions.

B) Nature of Operations

Within the newly restructured electric utility industry, BEC has announced its intention to focus its utility operations on the transmission and distribution of energy. In April 1998, Boston Edison began soliciting expressions of interest for the sale of Pilgrim Nuclear Power Station as part of the previously announced strategy to exit the generation business. Final bids for the purchase of Pilgrim were received on October 16, 1998. Boston Edison is currently evaluating those bids and anticipates signing a purchase and sale agreement by year-end 1998. Boston Edison provides standard offer service to all customers of record as of the retail access date, March 1, 1998. Default service is provided to customers who are not eligible for standard offer service or who elect to not contract with a competitive energy supplier. As of September 30, 1998, 90% of customers are receiving standard offer service, while 10% are receiving default service. No customers are receiving generation service from competitive suppliers. Boston Edison delivers electricity at retail to an area of 590 square miles, including the City of Boston and 39 surrounding cities and towns. It also supplies electricity at wholesale for resale to other utilities and municipal electric departments. Boston Edison is required to continue to develop and implement electric demand side management programs as well as to provide funding for renewable energy projects pursuant to the Massachusetts electric industry restructuring legislation enacted in November 1997.

C) <u>Contingencies</u>

1. Hazardous Waste

Boston Edison is an owner or operator of approximately 20 properties where oil or hazardous materials were spilled or released. As such, Boston Edison is required to clean up these remaining properties in accordance with a timetable developed by the Massachusetts Department of Environmental Protection. There are uncertainties associated with these costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. Boston Edison continues to evaluate the cleanup costs of these sites. It also faces possible liability as a potentially responsible party in the cleanup of five multi-party hazardous waste sites in Massachusetts and other states where it is alleged to have generated, transported or disposed of hazardous waste at the sites. Boston Edison is one of many potentially responsible parties and currently expects to have only a small percentage of the total potential liability for these sites. Through September 30, 1998, Boston Edison had approximately $6 million accrued on its consolidated balance sheet related to its cleanup liabilities. Management is unable to fully determine a range of reasonably possible cleanup costs in excess of the accrued amount, however based on its assessments of the specific site circumstances, it does not believe that it is probable that any such additional costs will have a material impact on its consolidated financial position. However, it is reasonably possible that additional provisions for cleanup costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

2. Generating Unit Performance Program

Boston Edison's generating unit performance program ceased March 1, 1998. Under this program the recovery of incremental purchased power costs resulting from generating unit outages prior to March 1, 1998 are subject to regulatory review. Proceedings relative to generating unit performance remain pending before the DTE. Management is unable to fully determine a range of reasonably possible disallowance costs in excess of amounts accrued, however based on its assessments of the information currently available, it does not believe that it is probable that any such additional costs will have a material impact on its consolidated financial position. However, it is reasonably possible that additional disallowance costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

3. Connecticut Yankee

Boston Edison is a 9.5% equity investor and power purchaser of Connecticut Yankee Atomic Power Company (CYAPC). The investment in CYAPC at September 30, 1998 is approximately $10 million and is included in equity investments on the consolidated balance sheet. In December 1996, the Board of Directors of CYAPC, which owns and operates the Connecticut Yankee nuclear electric generating unit, unanimously voted to retire the unit. The decision was based on an economic analysis of the costs of operating the unit through 2007, the period of the operating license, compared to the costs of closing the unit and incurring replacement power costs for the same period.

In December 1996, CYAPC filed for rate relief at the Federal Energy Regulatory Commission (FERC) seeking to recover certain post-operating costs, including decommissioning. On August 31, 1998, the FERC Administrative Law Judge (ALJ) released an initial decision regarding CYAPC's filing. This decision called for the disallowance of the common equity return on the CYAPC investment subsequent to the shutdown. The decision also stated that decommissioning collections should continue to be based on a previously approved estimate, with an adjustment for inflation, until a more reliable estimate is developed. In October 1998, both CYAPC and Northeast Utilities, a 49% equity investor in CYAPC, filed briefs on exceptions to the ALJ decision. If the initial decision is upheld, CYAPC could be required to write off a portion of its investment in the generating unit and refund a portion of the previously collected return on investment. Management is currently unable to determine the ultimate outcome of this proceeding, however, the estimate of the effect of the ALJ's initial decision does not have a material impact on its consolidated financial position or results of operations.

4. Industry and Corporate Restructuring Legal Proceedings/Referendum Campaign

The DTE order approving the Boston Edison settlement agreement and the DTE order approving the formation of BEC as a holding company have been appealed by certain parties to the Massachusetts Supreme Judicial Court. In addition, along with other Massachusetts investor-owned utilities, Boston Edison has been named as a defendant in a class action suit seeking to declare certain provisions of the Massachusetts electric industry restructuring legislation unconstitutional. Management is currently unable to determine the outcome of these proceedings or the impact the proceedings may have on its consolidated financial position or results of operations.

A referendum seeking repeal of the Massachusetts electric industry restructuring legislation that was enacted in November 1997 was overwhelmingly defeated by a better than 70% to 30% margin in a state-wide general election held on November 3, 1998. This outcome allows the comprehensive framework established for the restructuring of the electric industry to continue as intended under the enacted legislation.

5. Regulatory Proceeding

In October 1997, the DTE opened a proceeding to investigate compliance with the 1993 order which permitted the formation of BETG and authorized Boston Edison to invest up to $45 million in unregulated activities. The DTE has scheduled hearings on this matter for the fourth quarter. Management is currently unable to determine the outcome of this proceeding or the impact the proceeding may have on its consolidated financial position or results of operations.

6. Plymouth Lawsuit

In October 1998, the town of Plymouth, Massachusetts, the site of Pilgrim Nuclear Power Station, filed suit against Boston Edison. The town claims that Boston Edison has wrongfully failed to execute an agreement with the town for payments in addition to taxes due to the town under the recently enacted Massachusetts electric industry restructuring legislation. Boston Edison has disputed the town's claim and will vigorously defend itself. Management is unable to determine the ultimate outcome of this action or the impact it may have on its consolidated financial position or results of operations.

7. Litigation

In the normal course of its business Boston Edison is also involved in certain other legal matters. Management is unable to fully determine a range of reasonably possible legal costs in excess of amounts accrued, however based on the information currently available, it does not believe that it is probable that any such additional costs will have a material impact on its consolidated financial position. However, it is reasonably possible that additional legal costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

D) Income Taxes

The following table reconciles the statutory federal income tax rate to the annual estimated effective income tax rate for 1998 and the actual effective income tax rate for 1997.

	1998	1997
Statutory tax rate	35.0%	35.0%
State income tax, net of federal income tax benefit	5.1	4.5
Investment tax credit amortization	(6.8)	(3.3)
Other	0.8	0.1
Effective tax rate	34.1%	36.3%

The estimate of the 1998 effective tax rate declined by 5% as a result of the recognition in net income of the remaining unamortized investment tax credits related to Boston Edison's fossil generating assets at the time of their sale. This shareholder benefit is included in other expense, net in the consolidated statement of income for the nine-month period ended September 30, 1998.

E) Financing Activity

On May 15, 1998, Boston Edison closed the sale of its fossil generating assets and received total proceeds of $674 million in cash. $202 million of these funds were used to retire short-term debt securities. Boston Edison has no outstanding short-term debt on its September 30, 1998 consolidated balance sheet.

In June 1998, Boston Edison's $100 million 6.662% outstanding bank loan was redeemed. Boston Edison also redeemed $2 million of mandatory and $2 million of the optional 7.27% sinking fund series preferred stock in May 1998. In March 1998, $100 million of 5.95% debentures matured.

In July 1998, Boston Edison redeemed the remaining $32 million 7.27% sinking fund series preferred stock along with the $40 million 7.75% series preferred stock.

F) Related Party Transactions

The September 30, 1998 consolidated balance sheet of Boston Edison includes a $13 million receivable from BETG's telecommunications joint venture with RCN. The receivable is for construction and construction management services provided by Boston Edison and its contractors to the joint venture for its fiber optic network.

G) Nuclear Decommissioning

An update of Pilgrim Nuclear Power Station's decommissioning cost study was filed with the DTE in November 1998. The updated study includes an estimate of decommissioning and fuel storage costs of approximately $600 million in 1997 dollars.

Item 2. Management's Discussion and Analysis

Results of Operations - Three Months Ended September 30, 1998 vs. Three Months Ended September 30, 1997

The decrease in earnings reflects the effect of the mandated 10% retail rate reduction which became effective March 1, 1998 under the Massachusetts Electric Utility Restructuring Law. The decrease in earnings was partially offset by a decrease in operations and maintenance expense resulting from the fossil divestiture in May 1998 along with continued cost control efforts.

The results of operations for the quarter are not indicative of the results which may be expected for the entire year due to the seasonality of Boston Edison's kilowatt-hour (kWh, sales and revenues. Refer to Note A to the Consolidated Financial Statements.

Operating revenues

Operating revenues decreased 8.5% during the third quarter of 1998 as follows:

(in thousands)	
Retail electric revenues	$(37,519)
Wholesale revenues	(818)
Short-term sales and other revenues	(5,851)
Decrease in operating revenues	$(44,188)

Retail electric revenues decreased due to the 10% retail rate reduction which became effective for electricity usage as of March 1, 1998. The decrease from the rate reduction was partially offset by a 6.1% increase in kWh sales for the quarter. The increase in kWh sales was due to warmer summer temperatures and continued strong economic conditions in the Boston area.

Operating expenses

Energy supply expense includes fuel and purchased power, retail generation-related depreciation and amortization, decommissioning and other operating costs recovered through the transition charge. Energy supply expense decreased approximately $12 million. Total fuel and purchased power expenses decreased approximately $18 million. This decrease reflects lower company fuel costs and the timing effect of the fuel and purchased power and standard offer cost collection mechanisms. Lower fuel costs in the third quarter reflect the first full reporting period since the sale of Boston Edison's fossil generating assets to Sithe Energies in May 1998. This decrease was partially offset by higher purchased power costs that include a six-month transitional power purchase contract with Sithe that began in May. Boston Edison received $121 million from Sithe to enter into the transition contract. The capacity portion of the Sithe purchased power costs is offset by the recognition of the payment from Sithe and, therefore, has no net effect on earnings.

Operations and maintenance expense decreased $17.7 million. The decrease is primarily due to the impact of the fossil divestiture.

The decrease in depreciation and amortization expense is due to an $8.7 million nonrecurring charge to depreciation expense in the third quarter of 1997 to reflect the removal of specific nuclear-related intangible assets from the balance sheet. This was partially offset by an increase in the composite distribution depreciation rate effective March 1, 1998 in accordance with the settlement agreement.

The increase in demand side management (DSM) and renewable energy programs reflects an increase in the required spending for DSM programs in 1998. In addition, the renewable energy programs expense is the result of a new state mandate for the funding of renewable energy that became effective March 1, 1998. Renewable energy expenses are collected through distribution revenues and, therefore, have no net effect on earnings.

The decrease in property and other taxes is due to a decrease in municipal property taxes as a result of the divestiture of the fossil generating stations in May 1998.

Other income (expense), net

Other income in the third quarter of 1997 includes interest income from the favorable outcome of an IRS appeal related to investment tax credits.

Interest charges

Interest charges on long-term debt decreased due to the maturing of $100 million of 5.95% debentures in March 1998 and the cessation of amortization of the associated redemption premiums along with the redemption of a $100 million 6.662% bank loan in June 1998.

Interest charges on short-term debt decreased due to the redemption of Boston Edison's outstanding short-term debt with the fossil divestiture proceeds.

Preferred stock dividends

Preferred stock dividends decreased as a result of the redemption of 40,000 shares of 7.27% series cumulative preferred stock in May 1998, the remaining 320,000 shares of the 7.27% series in July 1998 and 400,000 shares of 7.75% series cumulative preferred stock in July 1998.

Results of Operations - Nine Months Ended September 30, 1998 vs. Nine Months Ended September 30, 1997

Earnings in 1998 were positively impacted by decreases in operations and maintenance expense, municipal property taxes and interest expense resulting from the fossil divestiture in May 1998. Warmer summer weather and the continued strong local economy also had a positive impact on earnings. These positive impacts were offset by the rate reduction mandated under Boston Edison's settlement agreement and an increase in unregulated subsidiary losses.

The results of operations for the nine months ended September 30, 1998 are not indicative of the results which may be expected for the entire year due to the seasonality of Boston Edison's kWh sales and revenues. Refer to Note A to the Consolidated Financial Statements.

Operating revenues

Operating revenues decreased 8.3% during the first nine months of 1998 as follows:

(in thousands)	
Retail electric revenues	$(107,512)
Wholesale revenues	(3,545)
Short-term sales and other revenues	(2,280)
Decrease in operating revenues	$(113,337)

Retail electric revenues decreased partly due to the timing effect of fuel and purchased power cost recovery. Prior to its cessation as of March 1, 1998, the fuel clause charge was lower than the prior year as the 1997 charge reflected the recovery of substantial prior period undercollections. Fuel clause revenues were offset by fuel and purchased power expenses and, therefore, had no net effect on earnings. Retail electric revenues also reflect the impact of the mandated 10% retail rate reduction. The rate reduction partially offset the impact of the 2.7% increase in kWh sales in 1998. Warmer than usual summer weather and the strong economic conditions in 1998 offset the negative impacts from the mild winter weather.

Operating expenses

Energy supply expense includes fuel and purchased power, retail generation-related depreciation and amortization, decommissioning and other operating costs recovered through the transition charge. Energy supply expense decreased approximately $85 million. Total fuel and purchased power expenses decreased approximately $93 million. The decrease in company fuel costs resulting from the fossil divestiture in May 1998 was significantly offset by an increase in purchased power subsequent to the divestiture. Purchased power costs include the six-month transitional power purchase contract with Sithe Energies that began in May. As the capacity portion of the Sithe purchased power costs is offset by the recognition of the payment from Sithe, those costs have no net effect on earnings. The timing effect of the fuel and purchased power and standard offer cost collection mechanisms also contributed to the decrease.

Operations and maintenance expense decreased approximately $32 million. The decrease reflects lower employee benefits costs, lower nuclear spending and the impact of the fossil divestiture. The comparison of 1998 and 1997 is also positively impacted by the April 1997 Boston area storm.

The decrease in depreciation and amortization expense is due to the $8.7 million nonrecurring charge in the third quarter of 1997 as discussed in the results of operations for the third quarter. This was partially offset by the increase in the composite distribution depreciation rate in accordance with the settlement agreement.

As discussed in the results of operations for the third quarter, the increase in DSM and renewable energy programs expense reflects an increase in the required spending for DSM programs in 1998. In addition, the renewable energy programs expense is the result of a new state mandate for the funding of renewable energy that became effective March 1, 1998. Renewable energy expenses are collected through distribution revenues and, therefore, have no net effect on earnings.

The decrease in property and other taxes is due to the decrease in municipal property taxes resulting from the fossil divestiture.

Other income (expense), net

The increase in other expense, net reflects certain costs related to the fossil divestiture, net of the related tax benefits, including the recognition of previously deferred investment tax credits associated with the fossil generating stations. Also negatively impacting the comparison of 1998 to 1997 is the interest income from the favorable outcome of an IRS appeal related to investment tax credits received in the third quarter of 1997. In addition, unregulated subsidiary losses were higher in 1998 as BETG's telecommunications joint venture with RCN began operations in the second quarter of 1997.

Interest charges

Interest charges on long-term debt decreased due to the maturing of $100 million of 5.70% debentures in March 1997, $100 million of 5.95% debentures in March 1998 and the cessation of amortization of the associated redemption premiums along with the redemption of a $100 million 6.662% bank loan in June 1998.

Interest charges on short-term debt decreased due to the redemption of Boston Edison's outstanding short-term debt with the proceeds from the fossil divestiture.

Preferred stock dividends

Preferred stock dividends decreased as a result of Boston Edison's redemption of 40,000 shares of 7.27% series cumulative preferred stock in May 1998 and 1997, the remaining 320,000 shares of the 7.27% series and 400,000 shares of 7.75% series cumulative preferred stock in July 1998 and 400,000 shares of 8.25% series in June 1997.

Electric Revenues

Effective March 1, 1998, the retail access date, Boston Edison's electric delivery business provides its standard offer customers service at rates designed to give 10% savings from rates previously in effect. These customers will realize an additional 5% average savings, after an adjustment for inflation, by September 1, 1999. The cost of providing standard offer service, which includes fuel and purchased power costs, is recovered from customers on a fully reconciling basis. New retail customers in the Boston Edison service territory and previously existing customers that are no longer eligible for the standard offer due to choosing a competitive supplier are on default service. The price of default service is based on the average competitive market price for power. Refer also to the Electric Revenues section of Item 7 of the Boston Edison 1997 Annual Report on Form 10-K.

As part of the restructuring settlement agreement, the annual performance adjustment charge ceased and the cost recovery mechanism for Pilgrim Station changed effective March 1, 1998. Approximately 25% of the operations and capital costs, including a return on investment, continues to be collected under wholesale contracts with other utilities and municipalities. Refer to the Electric Revenues section of Item 7 of the Boston Edison 1997 Annual Report on Form 10-K for a description of Pilgrim's new cost recovery mechanism.

The rates of Boston Edison's distribution business will remain unchanged, subject to a minimum and maximum return on average common equity (ROE) until December 31, 2000. Refer to the Electric Revenues section of Item 7 of the Boston Edison 1997 Annual Report on Form 10-K for detail regarding the minimum and maximum ROE. Under the Boston Edison settlement agreement, the cost of providing transmission service to distribution customers is recovered on a fully reconciling basis.

Liquidity

Boston Edison supplements internally generated funds as needed, primarily through the issuance of short-term commercial paper and bank borrowings. Boston Edison has authority from the Federal Energy Regulatory Commission to issue up to $350 million of short-term debt in addition to a $200 million revolving credit agreement and arrangements with several banks to provide additional short-term credit on an uncommitted and as available basis. It also has authority to issue up to $220 million of equity and long-term debt securities under its approved long-term financing plan with the DTE which is available through 1998. Proceeds from issuances under this plan are to be used to refinance short and long-term securities and to fund capital expenditures.

Year 2000 Computer Issue

The year 2000 issue is the result of computer programs that were written using two digits rather than four to define an applicable year. If computer programs with date-sensitive functions are not year 2000 compliant, they may recognize a date using "00" as the year 1900 rather than the year 2000. This could result in system failures or miscalculations causing disruptions of operations, including, among other things, a temporary inability to process transactions and engage in other normal business activities. Management has a year 2000 program in place that is addressing the risk of non-compliant internal business software, internal non-business software and embedded chip technology and external noncompliance of third parties.

Management's plan to address the year 2000 issue includes modification of certain applications and replacement of systems that are not year 2000 compliant. The cost associated with year 2000 compliance will be expensed as incurred. In addition, a decision has been made to use this opportunity to upgrade some of the less efficient centralized business systems. Replacement costs associated with these systems will be capitalized and amortized over future periods. Management estimates that it will expend approximately $30 million on these system modifications and upgrades. For each system designated as "critical" (defined as being necessary to safely provide a reliable flow of electricity), management's year 2000 program requires system testing and a contingency plan to be developed.

As part of the year 2000 program, significant suppliers, service providers and other vendors were contacted to determine year 2000 readiness. Many third parties have noted that they are already year 2000 compliant or in the process of becoming compliant. In addition to the risk faced from its dependence on other third party suppliers, Boston Edison has a risk that power will not be available from the New England Power Pool (NEPOOL) for purchase and distribution to its customers. Should NEPOOL fail to resolve its year 2000 issues as planned, there would be an adverse impact to Boston Edison. To mitigate this risk, efforts are being coordinated with NEPOOL to establish inter-utility testing guidelines to determine year 2000 readiness. Boston Edison is also a participant in the ISO/NEPOOL New England Year 2000 Joint Oversight Committee which has been given responsibility for the operational reliability of NEPOOL.

The year 2000 program remains on schedule with anticipated completion in the third quarter of 1999. However, management believes it is not possible to determine with complete certainty that all potential year 2000 problems have been identified or will be corrected due to the complexity and pervasiveness of the issue. In the event that compliance is not completed as anticipated, it is reasonably possible that the year 2000 issue could have an adverse effect on operations.

New Accounting Standards

In 1997, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 131, Disclosures about Segments of an Enterprise and Related Information (SFAS 131) which is effective in 1998. This statement requires the reporting of certain additional information about operating segments as applicable within an enterprise. SFAS 131 disclosure is not required for interim reporting in the initial year of application. Management will include the selected financial information and disclosures as required in its 1998 Annual Report on Form 10-K and its future interim reports on Form 10-Q as appropriate.

In June 1998, the FASB issued SFAS 133, Accounting for Derivative Instruments and Hedging Activities which is effective in 2000. This statement requires the recognition of all derivative instruments as either assets or liabilities in the statement of financial position and the measurement of those instruments at fair value. Management does not expect this statement to have a material impact on its consolidated financial position or results of operations.

The Accounting Standards Executive Committee of the American Institute of Certified Public Accountants issued Statement of Position 98-1, Accounting for the Costs of Computer Software Developed or Obtained for Internal Use (SOP 98-1) in March 1998. SOP 98-1, effective in 1999, provides specific guidance on whether to capitalize or expense costs within its scope. Management does not expect this SOP to have a material impact on its consolidated financial position or results of operations.

Safe Harbor Cautionary Statement

Management occasionally makes forward-looking statements such as forecasts and projections of expected future performance or statements of its plans and objectives. These forward-looking statements may be contained in filings with the Securities and Exchange Commission, press releases and oral statements. Actual results could potentially differ materially from these statements. Therefore, no assurances can be given that the outcomes stated in such forward-looking statements and estimates will be achieved. Refer also to the safe harbor cautionary statements included in the Boston Edison 1997 Annual Report on Form 10-K.

The preceding sections include certain forward-looking statements about environmental and legal issues and year 2000.

The impacts of various environmental and legal issues could differ from current expectations. New regulations or changes to existing regulations could impose additional operating requirements or liabilities other than expected. The effects of changes in specific hazardous waste site conditions and cleanup technology could affect estimated cleanup liabilities. The impacts of changes in available information and circumstances regarding legal issues could affect the estimated litigation costs.

The timing and total costs related to the year 2000 plan could differ from current expectations. Factors that may cause such differences include the ability to locate and correct all relevant computer codes and the availability of personnel trained in this area. In addition, management cannot predict the nature or impact on operations of third party noncompliance.

Part II - Other Information

Item 5. Other Information

Paul A. La Camera, age 55, was elected as a member of the Boston Edison Company Board of Directors, effective July 1, 1998. La Camera has been President and General Manager of WCVB-TV Channel 5 since 1997. From 1994 to 1997 he was Vice President and General Manager of the station.

The following additional information is furnished in connection with the Registration Statement on Form S-3 of the Registrant (File No. 33-57840), filed with the Securities and Exchange Commission on February 3, 1993.

Ratio of earnings to fixed charges and ratio of earnings to fixed charges and preferred stock dividend requirements:

Twelve months ended September 30, 1998:	
Ratio of earnings to fixed charges	3.11
Ratio of earnings to fixed charges and preferred stock dividend requirements	2.70

Item 6. Exhibits and Reports on Form 8-K

a) Exhibits filed herewith:

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

Boston Edison agrees to furnish to the Securities and Exchange Commission, upon request, a copy of any agreements or instruments defining the rights of holders of any long-term debt whose authorization does not exceed 10% of Boston Edison's total assets.

Exhibit 12 - Computation of Ratio of Earnings to Fixed Charges

12.1 - Computation of ratio of earnings to fixed charges for the twelve months ended September 30, 1998

12.2 - Computation of ratio of earnings to fixed charges and preferred stock dividend requirements for the twelve months ended September 30, 1998

Exhibit 15 - Letter Re Unaudited Interim Financial Information

15.1 - Report of Independent Accountants

Exhibit 27 - Financial Data Schedule

27.1 - Schedule UT

Exhibit 99 - Additional Exhibits

99.1 - Letter of Independent Accountants

Form S-3 Registration Statement filed by Boston Edison Company on February 3, 1993 (File No. 33-57840)

b) No Form 8-K was filed during the third quarter of 1998.

Signature

Pursuant to the requirements 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
(Registrant)

Date: November 16, 1998

/s/ Robert J. Weafer, Jr.
Robert J. Weafer, Jr.
Vice President-Finance,
Controller and Chief
Accounting Officer

Exhibit 12.1

Boston Edison Company
Computation of Ratio of Earnings to Fixed Charges
Twelve Months Ended September 30, 1998
(in thousands)

Net income from continuing operations	$148,999
Income taxes	71,445
Fixed charges	104,679
Total	$325,123
Interest expense	$ 95,394
Interest component of rentals	9,285
Total	$104,679
Ratio of earnings to fixed charges	3.11

Exhibit 12.2

Boston Edison Company
Computation of Ratio of Earnings to Fixed Charges
and Preferred Stock Dividend Requirements
Twelve Months Ended September 30, 1998
(in thousands)

Net income from continuing operations	$148,999
Income taxes	71,445
Fixed charges	104,679
Total	$325,123
Interest expense	$ 95,394
Interest component of rentals	9,285
Subtotal	104,679
Preferred stock dividend requirements	15,622
Total	$120,301
Ratio of earnings to fixed charges and preferred stock dividend requirements	2.70

Exhibit 15.1

Report of Independent Accountants

To the Directors of
Boston Edison Company

We have reviewed the accompanying consolidated balance sheet of Boston Edison Company (Boston Edison) as of September 30, 1998 and the related statements of income for the three and nine-month periods ended September 30, 1998 and 1997 and cash flows for the nine-month periods ended September 30, 1998 and 1997. These financial statements are the responsibility of Boston Edison's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures to financial data and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying financial statements in order for them to be in conformity with generally accepted accounting principles.

Boston, Massachusetts
October 22, 1998

PricewaterhouseCoopers LLP

Exhibit 99.1

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: Boston Edison Company
Registration on Form S-3

We are aware that our report dated October 22, 1998 on our review of the interim financial information of Boston Edison Company (Boston Edison) for the period ended September 30, 1998 and included in this Form 10-Q is incorporated by reference in Boston Edison's registration statement on Form S-3 (File No. 33-57840). Pursuant to Rule 436(c) under the Securities Act of 1933, this report should not be considered a part of the registration statement prepared or certified by us within the meaning of Sections 7 and 11 of that Act.

Boston, Massachusetts
October 22, 1998

PricewaterhouseCoopers LLP

BOSTON EDISON COMPANY

1999 INTERNAL CASH FLOW PROJECTION
FOR PILGRIM UNIT #1 NUCLEAR POWER STATION
(DOLLARS IN THOUSANDS)

	12 Months Ended 9/30/98	Projected Year 1999
Net Income After Taxes	$ 148,999	$ 150,000
Less Dividends Paid (A)	(102,555)	(99,000)
Retained Earnings	46,444	51,000
Adjustments		
Depreciation and Amortization	231,185	225,000
Deferred Taxes and ITC	(149,668)	(120,000)
AFUDC	(1,215)	(1,400)
Total Adjustments	$ 80,302	$ 103,600
Internal Cash Flow	$ 126,746	$ 154,600
Average Quarterly Cash Flow	$ 31,687	$ 38,650
Percentage Ownership in All Operating Nuclear Units	Pilgrim Unit #1 = 74.27%	
Maximum Total Contingency Liability		$ 10,000

(A) Excludes special dividend of $70 Million dollars paid to BEC Energy upon divestiture of the Company's Fossil Generation Units.

ITEM (4) NARRATIVE STATEMENTS OF CURTAILMENT OF CAPITAL EXPENDITURES:

The Boston Edison Company would be able to curtail $10 million of capital expenditures within any three month period of the next twelve months if it becomes necessary to pay retrospective premiums.

1997 Annual Report

Boston Edison

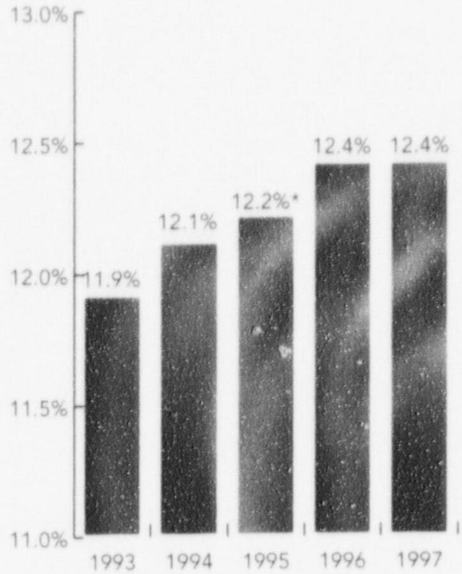
1997 Annual Report

Boston Edison

Earnings Per Share

* 1995 amount excludes a $0.44 restructuring charge.

Return On Equity



* 1995 percentage excludes a $0.44 restructuring charge.

FINANCIAL HIGHLIGHTS

	years ended December 31, 1997	1996
Operating revenues (000)	$ 1,776,233	$ 1,666,303
Earnings available for common (000)	$ 131,493	$ 126,181
Weighted average common shares outstanding (000)	48,515	48,265
Common stock data:		
Earnings per share	$ 2.71	$ 2.61
Dividends declared per share	$ 1.88	$ 1.88
Payout ratio	69 %	72 %
Book value per share	$ 22.13	$ 21.37
Return on average common equity	12.4 %	12.4 %
Fixed charge coverage (SEC)	2.95	2.91

CONTENTS

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DEAR SHAREHOLDER

Dramatic and successful. Strong words, but they accurately reflect the results of 1997.

For the past two years, in my annual letter to you, I have discussed changes expected in the industry and the company as a result of deregulation of energy supply. Now it has happened. Your company has emerged from the uncertainty of the past in a strong position for future success. But 1997 was more, much more, than the culmination of the anticipated changes in energy markets. It marked, as well, a significant change in our core business of generating electricity, with the decision to sell our oil and natural gas power plants.

Perhaps most importantly, as it relates to our future, our employees went the extra mile throughout the year for our customers and for you, our shareholders. The results speak for themselves:

- Total shareholder return was 51 percent as the company's share price climbed 41 percent.
- Earnings per share increased to $2.71.
- Field operations were redesigned around customer expectations, resulting in significant productivity and service improvements.
- Nearly a dozen new customer services were introduced.
- Legislation passed that assures customers of energy savings and choice of energy suppliers, while providing for full recovery of stranded costs.
- Sale of our oil and gas-fired power plants attracted a 50 percent premium.

These results alone are impressive. However, by themselves they mask the fact that the sale of our power plants makes us a smaller company. While we have exited the electric generation business, we are in an excellent position to pursue new opportunities for growth. We have adopted an ambitious vision of the future. We see a company with two million customers in the year 2000, a three fold increase in three years. That growth will come from a combination of geographic expansion in electricity delivery, and possibly gas delivery, and from our joint ventures.

Ours is a vision that capitalizes on the restructuring of energy markets, as well as their convergence with telecommunications markets. That vision, and steps already taken to achieve it, prompted McGraw-Hill Publishing's *Electrical World* magazine to award your company the 1997 James H. McGraw Award for Corporate Excellence. The award was presented because of "the company's visionary restructuring and diversification efforts" and "its groundbreaking corporate strategy." As the award notes, the strategy "continues to strengthen the company's commitment to the end user."

This report is about that commitment and about the employees who make it real.

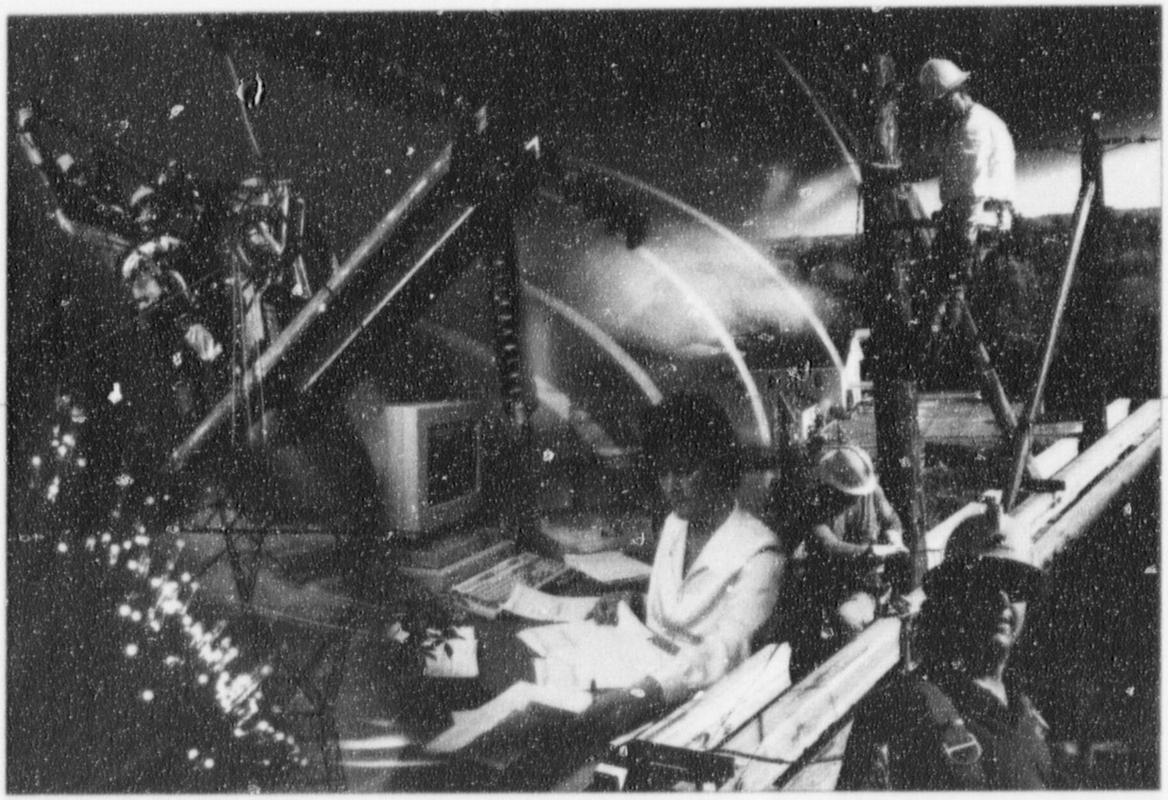
Thomas J. May

Tom May

Chairman, President and Chief Executive Officer

COMMITMENT TO CUSTOMERS

McGraw-Hill, in selecting the company for the 1997 James H. McGraw Award for Corporate Excellence, recognized it for its "commitment to the end user." Ours is the last major industry to go through deregulation, after the airlines, telecommunications, trucking and natural gas. The public policy initiatives producing competition in the electric utility industry are driven by a combination of new technologies, and customers who expect and want to have choices.



People and technology are coming together to change public policy and create competition in what had been a completely regulated monopoly industry. At Boston Edison, people and technology are also coming together — working together — to make a difference in delivering comfort, convenience and efficiency to customers. Boston Edison and the reliable delivery of electricity will be the core of the new holding company, BEC Energy.

In 1997, all aspects of the electric delivery business underwent transformation. Key business activities, such as electric system construction and services, asset management, metering and all aspects of customer care, were restructured around customer requirements and the processes necessary to meet them. The new business processes capture the best practices of world-class companies, domestic and foreign.

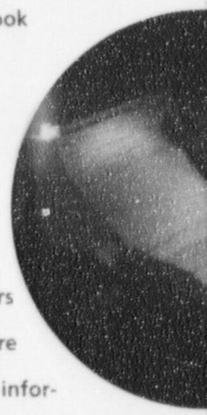
This transformation is the result of a highly disciplined, customer-focused, strategic assessment of process, people and technological needs for a high performing "delivery" business.

To make the processes work, multi-disciplined teams are in place throughout Boston Edison. Separately, an asset management team focuses on investment planning and technology selection to ensure that the delivery network provides a high level of performance to achieve customer satisfaction and financial return.

Meanwhile, new customer service initiatives have been built around the principle of ease of doing business. These initiatives give customers options, and provide accurate and timely information and personalized service. New services introduced in 1997 included direct payment, Internet access to account information, appointment scheduling, and consolidated billing for customers with multiple accounts. Also introduced was a new storm response management and information system. This new system will shorten restoration time and provide customers with better information about restoration progress.

As the changes described above were being implemented, major work continued to upgrade the existing distribution system in and around the City of Boston. We also introduced a major expansion of our automated meter reading system and further improvement in our remote monitoring and switching capabilities. Both significantly improve productivity and customer information.

A new look for the Boston Edison bill provides customers with more detailed information in an easier to read format.



WHAT CUSTOMERS CAN EXPECT FROM ELECTRIC UTILITY DEREGULATION

The following is some basic information Boston Edison has been providing its customers about deregulation, which started March 1, 1998.

Why was March 1 important?

That was when the production of electricity was officially "deregulated." That means that power plants will no longer be part of the regulated monopoly customers have known for decades. The electric utility, such as Boston Edison, will still deliver the electricity. But it will act more like Federal Express -- delivering the package of power you will purchase from among an array of producers. March 1 was also the date when electric utility rates -- the cent-per-kilowatt hour price -- went down 10 percent.

Does that mean the bill will go down 10%?

The price per kilowatt-hour will go down. Customers who use the same amount in March as during an earlier month, will see a 10 percent reduction. But consumption varies due to many factors, including weather, which affects the total bill. It is important to look at both the rate and the usage.

Will customers actually have to decide where to buy their electricity?

No, not initially. They may choose to do nothing, to just continue getting power -- production and delivery -- from the utility. The utility may not be producing it, but it will buy it for customers during the transition from monopoly to full competition.

Customers will be able to choose the company that produces power. Boston Edison will continue to deliver that power.

After March 1, who will customers call if the lights go out?

Customers will continue to call their local utility that delivers their electricity. That will not change.

Who will be responsible for ensuring a reliable supply of electricity?

The electric utility -- the delivery company -- will continue to be responsible for a reliable transmission and distribution system. But making sure there is enough production capacity will be the result of market forces -- supply and demand. Already, in anticipation of pending competition, power producers have announced new plants to meet anticipated demand for lower priced power.

STRENGTHENING THE ECONOMY AND THE COMMUNITY -- EQUALLY IMPORTANT

Civic involvement and environmental stewardship remain an important aspect of Boston Edison Company's activities. The changes occurring in the electric utility industry do not diminish the importance of a vibrant economy, a clean environment and healthy communities to the well being of the company, its customers and its employees.

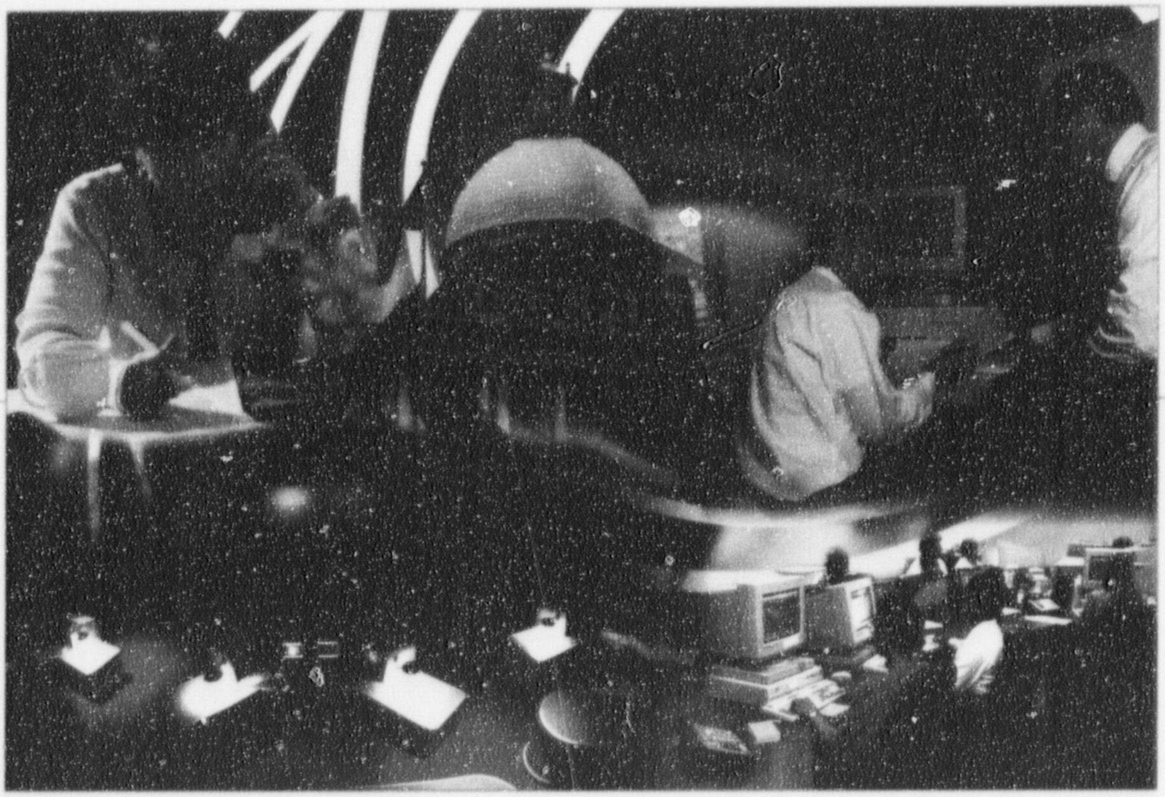
Over the years, the company has been active in programs to help the economy and the communities in which it does business. In 1997, the company continued to work with state and local governments on quality of life issues. For example, Chairman, President and CEO Tom May chairs the Governor's Council on Economic Growth and Technology. The focus last year was on three issues - business support for quality education, continued progress on reducing the cost of doing business in Massachusetts, and initiatives to market Massachusetts to prospective employers. Internally, the company's economic development initiatives continued to help attract employers such as Sun Microsystems to the service area.

On the environmental front, the company worked closely with various interests to attract alternative fuel vehicle manufacturers to the area and to establish incentives for vehicle purchases. It helped attract federal funding for fleet operators to offset incremental costs of clean fuel technologies.

Finally, the company's philanthropic efforts were concentrated in the areas of education, the environment, health and human services, community development and the arts. It continued to help Boston Mayor Tom Menino implement the Kids Compute 2001 program, which is ahead of schedule as more and more companies step forward to participate.

THE ARRIVAL OF COMPETITION AND CUSTOMER CHOICE

For the past half decade, following passage of the National Energy Act of 1992, government, business, utility industry, consumer, academic and environmental leaders have been collaborating to restructure the electric utility industry. The parties represented many interests and often opposing viewpoints. Out of this process, a set of principles emerged in 1995 and 1996 which Boston Edison has supported.



In July 1997 Boston Edison finalized its deregulation settlement agreement with the Massachusetts Attorney General, the Massachusetts Division of Energy Resources and various customer and environmental groups. Implementation of the settlement required state legislation and approval by the Massachusetts Department of Telecommunications and Energy (DTE). Both have been achieved. The Massachusetts Legislature passed, by overwhelming majorities in both Houses, legislation that implements customer choice and competition for energy supply beginning in March 1998. "Landmark" may be an overused word to describe significant events. In this case, it seems appropriate.

The legislation is a well-balanced approach to meeting the needs of customers, stockholders, communities hosting power plants and our employees. It assures all customers of a 10 percent rate reduction in 1998 followed by a further five percent reduction by September 1, 1999. It provides for full recovery of stranded costs while providing incentives for mitigating those costs. This is discussed more fully in the section on divestiture. Communities with power plant sites are protected against property tax losses as power plants are revalued. Additionally, the legislation maintains the state's commitment to those customers in need of assistance and to the deployment of energy conservation measures and the use of renewable energy.

The steps necessary to implement the legislation are now being taken. The company worked toward that end for much of 1997. By year-end, virtually all internal systems and infrastructure needed to implement customer choice were in place.

These internal changes were moving in concert with regulatory proceedings before the DTE. The DTE considered specific filings from Boston Edison on the settlement and establishment of the holding company, BEC Energy. It also had to consider and act on new terms and conditions for customers and for energy suppliers and registration requirements for suppliers and marketers. The DTE has been able to keep to an aggressive schedule and meet the legislative requirements for competition and approval of settlements reached by Boston Edison and other utilities. We are awaiting a decision from the DTE regarding our reorganization plan to form BEC Energy.

Employees worked throughout 1997 to prepare for electric utility deregulation.

As a result, the company set an ambitious schedule in 1997 to sell its oil and natural gas power plants. This was based on the belief that plants sold early would be the most attractive and would command the best price, as potential buyers jockeyed to gain a presence in this emerging market. We were correct.

By spring, letters seeking expressions of interest had been sent to 1,500 organizations considered potential buyers. By summer, plant visits and meetings had begun as those interested were being qualified. Moving in parallel with debate over the restructuring legislation, the company narrowed the list of bidders, with bids due December 3, 1997, just two weeks after the legislation was passed.

We had urged lawmakers to act in 1997, arguing that it would allow our customers to benefit from the intense market interest. This would lead to a higher purchase price and reduce rates charged to our customers.

When the bids were opened and the winner announced on December 10, the aggressive strategies to push for House and Senate votes in support of the legislation — and to sell the oil and natural gas power plants — were validated.

Sithe Energies won the bidding, paying a total of $657 million. Against a book value of $450 million, Sithe's bid provided $536 million for the assets at five generating sites in and near Boston and $121 million for a transition purchase power contract.

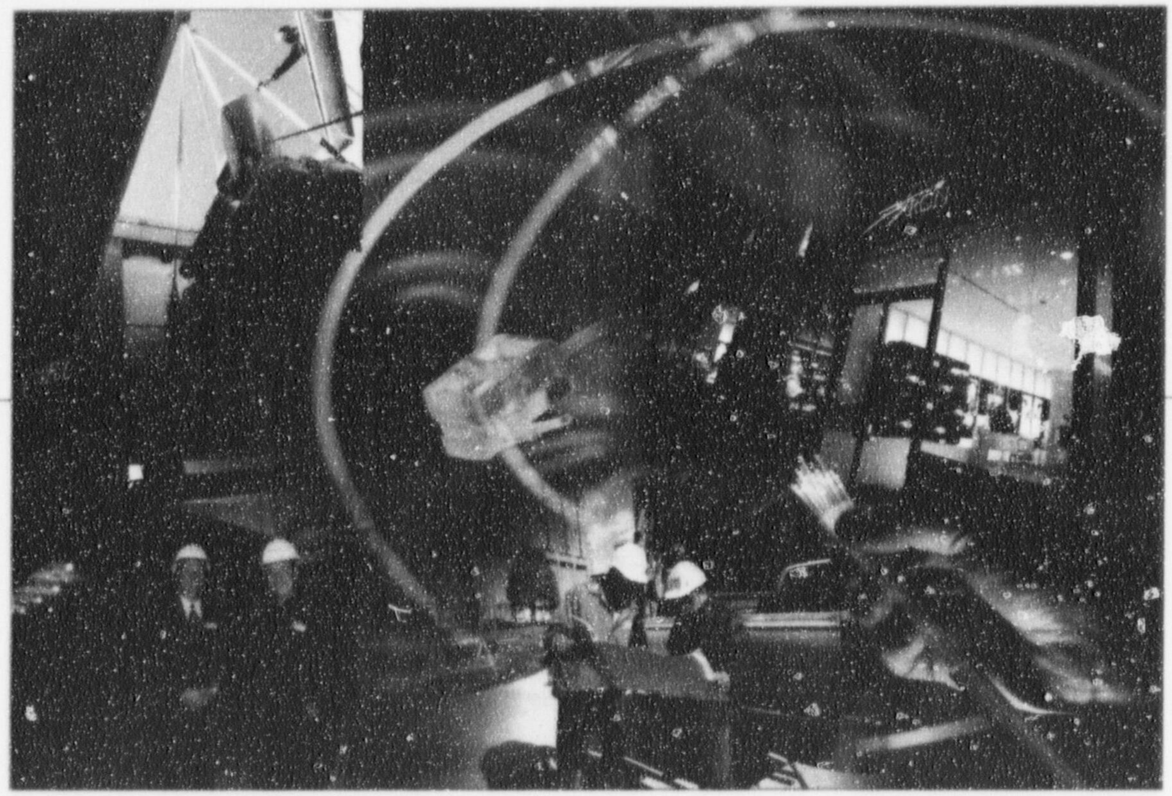
Sithe Energies tops the competitive bidding with an offer of $657 million for five generating plants and a transitional purchase power contract.

Sithe cited competition and the recently passed legislation as the reasons for its interest in Massachusetts. Indicative of how it views the new market, Sithe also announced that it would invest more than $1 billion at the sites to build 2,800 megawatts of new, highly efficient generating capacity while keeping the 2,000 megawatts it purchased operating. This is testimony to our employees and to the position Massachusetts has staked out in restructuring. It bodes well for Boston Edison since the Massachusetts and New England economies should benefit from the energy price impacts of competition. The sale is expected to be completed by the middle of May.

Next to be addressed is the future of the Pilgrim Nuclear Power Station. In 1997, Pilgrim completed its shortest refueling outage in history. The plant continued to perform well, as it has throughout the 1990s. Under the settlement agreement which led to the sale of the oil and gas-fired plants, the company will recover transition costs associated with Pilgrim, including decommissioning costs. Boston Edison is required to develop and file by January 1, 1999 with the Department of Telecommunications and Energy a plan for valuing Pilgrim. Among the options are creation of a regional or national alliance of nuclear plants or outright sale. In any case, the plant's physical condition is good, the plant is operating well and the staff is highly motivated.

NEW AFFILIATIONS... NEW DIRECTIONS

The company's new involvement in telecommunications got off to a strong start in 1997. The telecommunications joint venture with RCN attracted a lot of national media interest — and many new customers. RCN/Massachusetts, in which Boston Edison is a 49 percent owner, is viewed as a national model for utility entry into telecommunications markets. RCN is a facilities-based telecommunications company offering bundled telephone, cable and Internet access for delivery over fiber optic networks.



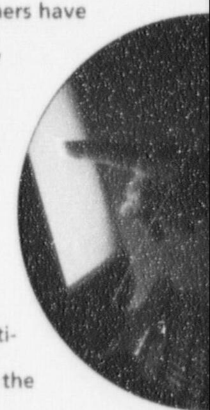
RCN's overall customer count totaled approximately 20,000 by the end of 1997. It has attracted intense interest from communities throughout Greater Boston and around the state, especially regarding its cable television service. This is largely because for the first time established cable television companies are running into direct competition. An often-cited example is the City of Somerville, next to Boston. In that city, Time Warner chose not to impose a 10 percent rate increase last fall, simply because of the competition from RCN. Other cities and towns are taking notice, and RCN is signing video agreements with communities at the rate of one per month.

EnergyVision, an energy marketing joint venture with The Williams Companies of Tulsa, Oklahoma, showed modest growth in 1997, primarily in the natural gas market. The electricity market in New England did not develop as quickly as anticipated. This is expected to change, however, as states such as Massachusetts open their markets, and independent generating companies such as Sithe Energies develop new projects.

At another company affiliate, Northwind Boston, construction began on its first district cooling plant located at The First Church of Christ, Scientist in Boston. The plant will be ready to serve customers in Boston's Back Bay District in June, 1998. Northwind is 75 percent owned by Boston Edison and 25 percent owned by Unicom Thermal of Chicago.

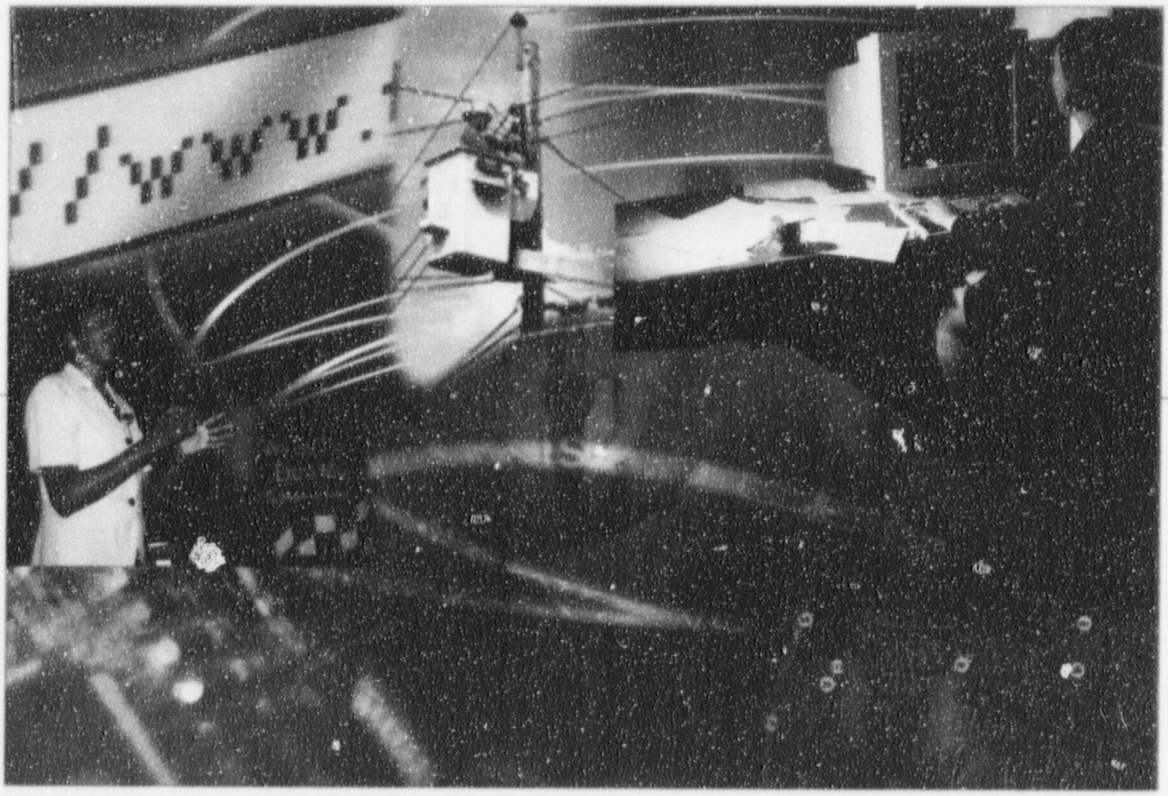
Coneco, a wholly-owned energy services company, signed significant contracts in New York and Florida and several other states during the year. While it continued to grow, the pace slowed somewhat in late 1997 due to energy conservation funding cutbacks for New York State schools.

Customers have already begun to realize the benefits of competition in the cable industry through our relationship with RCN.



THE FUTURE

Our success in 1997 was built around people, processes and technologies working together to serve customers. The company was featured in publications such as TIME magazine, the Wall Street Journal, the New York Times and Forbes because of its focus on strategies for success under competition. The vision, and the strategies for accomplishing it, are well defined and being implemented.



There has never been a more exciting time in the electric utility industry. And with the challenges of deregulation come opportunities for growth. In 1998, we expect to see the beginning of dramatic changes in the structure of the utility industry in New England. Now that the rules of competition and restructuring are becoming clear, consolidation appears inevitable. The company expects to be part of that consolidation as the territorial maps of utility service areas are redrawn. Geographic expansion is a major part of the company's strategy for growth.

The year 1998 will have its challenges. The rate reduction of 10 percent, as well as the infrastructure necessary to achieve customer choice, will challenge our employees. The strict cost control measures and productivity improvements that have been implemented in the recent past will continue. Yet, the company is in a good position for growth because of investments in technology, improvements in operations and a highly skilled workforce.

The strong management team that produced the results of the last few years, especially the results of 1997, is well positioned to lead Boston Edison. We will continue to balance the ongoing, day-to-day needs of the company while embracing each opportunity to grow and prosper.

In 1997, Boston Edison received national recognition from McGraw Hill for Corporate Excellence.

"Boston Edison is being recognized for its ground breaking corporate strategy that was initiated well in advance of state regulatory mandates and continues to strengthen the company's commitment to the end user"

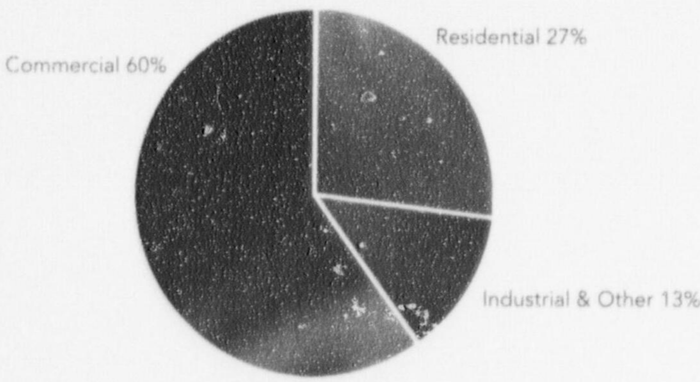
Mariel Leone
Electrical World
Editor-in-chief
Commenting on Boston Edison's selection for McGraw Hill's Corporate Excellence Award

FINANCIAL SECTION

Dividends Paid Per Share

Capital Expenditures (in millions)

Retail Customer Sales Mix



Management's Discussion and Analysis

Electric Utility Industry Restructuring

The traditionally rate-regulated electric utility industry is rapidly changing in response to the continuing market pressures for lower-priced electric energy. These pressures have resulted in regulatory and legislative proceedings at both federal and state levels designed to foster competition in the industry. On January 28, 1998, the Massachusetts Department of Telecommunications and Energy (DTE), formerly the Department of Public Utilities (DPU), approved our restructuring settlement agreement that was filed in July 1997. The DTE found that the settlement agreement substantially complied or was consistent with key provisions of a Massachusetts law enacted in November 1997 establishing a comprehensive framework for the restructuring of our industry. Major provisions of our settlement agreement include the ability for retail electric customers to choose their electricity supplier (referred to as retail access) as of March 1, 1998 (the retail access date). Customers who choose not to participate in retail access will have the option of continuing to buy power from our electric delivery business at "Standard Offer" prices. Upon the retail access date, customers that continue to buy electricity under the Standard Offer will realize an average 10% savings from the rates in effect during 1997. Under the new legislation, Standard Offer customers will realize another 5% savings in electricity rates, after an adjustment for inflation, by September 1, 1999. We expect to be able to meet this additional rate reduction as a result of the divestiture of our fossil generating assets which is discussed below. As part of our settlement agreement, the retail delivery rates of our retained distribution business include a non-bypassable transition charge designed to recover certain costs incurred by our generation business under the traditional electric ratemaking structure which cannot be otherwise recovered in a competitive environment. The rates of our distribution business will continue to be regulated by the DTE based on the cost of providing distribution service.

In 1997 the Emerging Issues Task Force (EITF) reached consensus on specific issues raised related to the application of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71). As part of its consensus, the EITF determined that when deregulation legislation is passed and regulatory actions have taken place providing sufficient detail for an enterprise to reasonably determine how the transition plan will affect the separable portion of its business being deregulated, the enterprise should stop applying SFAS 71 to that portion of its business. As a result of the recently passed Massachusetts electric industry restructuring legislation and the DTE order regarding our related settlement agreement, we have determined that, as of December 31, 1997, the provisions of SFAS 71 no longer apply to the generation portion of our business. The EITF further determined that book values of assets and liabilities originating in the separable portion of the business no longer subject to rate-regulation should be evaluated on the basis of where the regulated cash flows to realize and settle them will be derived. Net generating assets recoverable from the proceeds of the fossil divestiture and through the non-bypassable transition charge of our distribution business which continues to be subject to rate-regulation, therefore, remain on our consolidated balance sheet at December 31, 1997. In addition, approximately 25% of the operations and capital costs, including a return on investment, of Pilgrim Nuclear Power Station will continue to be collected under wholesale life of the unit contracts. These contracts continue to be regulated by the Federal Energy Regulatory Commission (FERC) and are not impacted by our settlement agreement.

Divestiture of Fossil Generating Assets

Our restructuring settlement agreement includes a provision for the divestiture of our fossil generating assets no later than six months after the retail access date. On December 10, 1997, we entered into a purchase and sale agreement with Sithe Energies, Inc., a privately-held company headquartered in New York, to purchase our non-nuclear generating assets. The proceeds from the sale of these assets will be $657 million. The net book value of these assets at December 31, 1997 is approximately $450 million. Included in the purchase price, Sithe Energies will pay $121 million to us in connection with a six-month transitional power sales agreement under which we will buy power from the generating plants. Sithe Energies will also be responsible for obligations resulting from the recently enacted utility restructuring legislation for property tax payments to communities with non-nuclear power plants. Net proceeds from the divestiture will be used to reduce the distribution transition charge.

Implementation of the divestiture plan is subject to certain regulatory approvals including those of the DTE and the FERC. We anticipate finalization of the divestiture in mid-1998.

In July 1997, we reached an agreement with our field service union that requires the buyer of our fossil generating assets to recognize and continue to honor the provisions of the union's current collective bargaining agreement through the end of its term, May 2000. As part of a package offered to employees affected by the fossil divestiture, all eligible fossil and designated fossil support employees age 55 or older with at least 10 years of service, or age 65 by July 1, 1998, were offered unreduced retirement and transition benefits under a voluntary early retirement program (VERP). Under this program, 40 people elected to retire. Retirement dates are expected to be the first of the month following the transfer of ownership of our fossil generating assets. Severance programs were offered to management and field service union employees affected by the fossil divestiture that did not elect or were ineligible to retire under the VERP. These severance benefits include salary payments, education/retraining allowances and outplacement services. It is anticipated that 48 employees will receive severance benefits under these programs.

The estimated costs associated with the VERP and severance programs is approximately $21 million including the effects on the retirement, life and dental plans. Severance and employee retraining costs related to the divestiture are recoverable through the distribution transition charge under our settlement agreement. Therefore, we have established an offsetting regulatory asset for these obligations on our consolidated balance sheet at December 31, 1997.

Nuclear Asset Impairment

As part of the settlement agreement, we recover our net investment in Pilgrim as of December 31, 1995 (adjusted for depreciation through 1997) through the distribution transition charge. Under the terms of the settlement agreement, we must perform a market valuation of Pilgrim by 2002. Upon acceptance of the valuation by the DTE, the resulting dollar amount, net of prudently incurred post-1995 investments in the plant, will reduce amounts collectible through the transition charge. If the valuation is not sufficient to allow for the recovery of these investments, we will seek their recovery through the transition charge. Due to the market pressures facing us, the ultimate recovery of these assets is not certain. Therefore, we reduced our investment in Pilgrim by the $13 million invested in the plant since January 1, 1996 as an impairment loss. An after tax charge of approximately $8 million due to this reduction was recorded to non-operating expense on our consolidated statement of income in the fourth quarter of 1997. A similar uncertainty does not exist for the ultimate recovery of the fossil generating assets as the sale proceeds agreed to in the purchase and sale agreement with Sithe Energies exceeds the net book value of these assets.

BEC Energy

We are currently awaiting a decision from the DTE regarding our reorganization plan to form a holding company structure. A decision from the Securities and Exchange Commission is also pending. Approval from the Nuclear Regulatory Commission was received on February 11, 1998. This plan was approved by the FERC and our shareholders in 1997. This new structure will clearly separate our regulated and unregulated operations. It will provide us with greater organizational flexibility allowing us to take advantage of nonutility business opportunities in a more timely manner. The holding company structure is a well-established form of organization for companies conducting multiple lines of business. In fact, all other investor-owned Massachusetts electric utilities are currently organized in this manner. Through our holding company, BEC Energy, we will seek ways to expand our customer base.

Joint Ventures

We continue to conduct unregulated activities through our wholly owned subsidiary, Boston Energy Technology Group (BETG). During 1997, BETG entered into two joint venture agreements. BETG has a joint venture agreement with RCN Telecom Services, Inc. (RCN). The final closing on this joint venture occurred in June 1997. This limited liability company (LLC) competes directly with local and long-distance telephone, video and Internet access companies for telecommunications-related services. BETG owns 49% of the LLC while RCN owns 51% and maintains day-to-day management responsibility. BETG also has an energy marketing venture with Williams Energy Services Company (WESCO), a subsidiary of The Williams Companies, Inc. This LLC, EnergyVision, markets electricity, natural gas and energy-related services to retail customers in the six New England states and began operations in February 1997. BETG and WESCO each own 50% of EnergyVision.

Results of Operations

1997 versus 1996

Earnings per share of common stock were $2.71 in 1997 compared to $2.61 in 1996, a 3.8% increase as described below.

Operating revenues

Operating revenues increased 6.6% over 1996 as follows:
(in thousands)

Retail electric revenues	$ 87,252
Demand side management revenues	1,232
Wholesale revenues	(765)
Short-term sales and other revenues	22,211
Increase in operating revenues	$109,930

Retail base revenues, consistent with the 0.8% increase in kilowatt-hour (kWh) sales in 1997, were relatively flat compared to 1996. Increases due to warmer than normal temperatures in June and July, cooler temperatures in October and December and the stronger local economy were offset by milder than normal winter conditions during the first quarter of 1997 and lower industrial sales. Industrial sales continue to be adversely affected by the decline in manufacturing activity in our service territory. In addition, revenues in 1996 reflect one more day of sales due to the leap year. Total retail electric revenues increased $87.3 million primarily due to the timing effect of fuel and purchased power cost recovery. The increase in fuel and purchased power clause revenues reflect the current recovery of prior year undercollections. These higher revenues are offset by higher fuel and purchased power expenses and, therefore, have no net effect on earnings. Pilgrim performance revenues, which vary annually based on the operating performance of Pilgrim Station, decreased due to a lower annual capacity factor effective November 1996 reflecting the refueling and maintenance outage in the first quarter of 1997.

Short-term sales revenues increased approximately $16 million. This is due to the continued reduction in available nuclear energy supply in New England combined with a 42% increase in our fossil generation allowing for increased sales to the power exchange. Revenues from short-term sales result in a corresponding reduction to future fuel and purchased power billings to retail customers and, therefore, have no net effect on earnings.

Operating expenses

Fuel and purchased power expenses increased $90.2 million. This increase reflects $57 million related to the timing effect of fuel and purchased power cost recovery. In addition, company fuel expense increased $50 million primarily due to the 42% increase in fossil generation. These increases were partially offset by a $22 million decrease in power exchange purchases. Fuel and purchased power expenses are substantially recoverable through fuel and purchased power revenues.

Operations and maintenance expense decreased $2.6 million from 1996. The decrease is the result of lower spending due to overall cost control efforts and significantly less overhaul activity at our fossil generating units. These decreases were partially offset by an approximately $5 million incremental impact associated with service restoration efforts resulting from a severe snow storm in April 1997 that struck the greater Boston area.

The increase in depreciation and amortization expense is due to the net impact of two depreciation adjustments. We recorded an $8.7 million nonrecurring charge to depreciation expense in the third quarter of 1997 to reflect the removal of specific nuclear-related intangible assets from our balance sheet. In 1996 we recorded a $5.2 million adjustment to correct the accumulated depreciation balance of certain large computer equipment.

Income taxes increased as a result of higher net income offset by a lower effective tax rate. The effective tax rate for 1997 reflects the impact of the favorable outcome of an Internal Revenue Service (IRS) appeal received in the third quarter related to investment tax credits (ITC). This also resulted in an increase in unamortized ITC which will be reflected as a reduction to income tax expense over the life of the related assets. Refer to Note D to the Consolidated Financial Statements for more information on income taxes.

Other expense

Other expense, net in 1997 reflects the charge of approximately $8 million, after tax, from the nuclear asset impairment which is further discussed in Note C to the Consolidated Financial Statements in addition to BETG equity losses. These decreases were partially offset by approximately $3 million, after tax, in interest income from the IRS appeal.

Interest charges

Total interest charges on long-term debt decreased due to the maturing of $100 million of 5.70% debentures in March 1997 and the cessation of amortization of the associated redemption premiums. This was partially offset by the March 1997 issuance of $100 million of 6.662% bank debt due in 1999. The decrease also reflects the maturity of $100 million of 5 1/8% debentures in March 1996.

Allowance for borrowed funds used during construction (AFUDC), which represents the financing costs of construction, decreased primarily due to a lower average construction work in progress (CWIP) balance in 1997. The 1996 average CWIP balance included nuclear fuel purchased in anticipation of Pilgrim Station's scheduled refueling outage in the first quarter of 1997.

Preferred stock dividends

The decrease in preferred stock dividends is the result of the redemption of 20,000 of mandatory and 20,000 of optional shares of 7.27% series cumulative preferred stock in May 1997 and 400,000 shares of 8.25% series in June 1997. Refer to Note I to the Consolidated Financial Statements.

1996 versus 1995

Earnings per share of common stock were $2.61 in 1996 compared to $2.08 in 1995. Earnings in 1995 reflect a nonrecurring before tax charge of $34 million ($20.7 million after tax, or $0.44 per share) associated with our corporate restructuring. The restructuring is discussed further in Note F to the Consolidated Financial Statements. Excluding the nonrecurring restructuring charge, earnings per common share increased 3.6% over 1995 as described below.

Operating revenues

Operating revenues increased 2.3% over 1995 as follows:
(in thousands)

Retail electric revenues	$48,649
Demand side management revenues	(20,545)
Wholesale revenues	(2,072)
Short-term sales and other revenues	11,768
Increase in operating revenues	$37,800

Retail electric revenues increased $48.6 million. Fuel and purchased power clause revenues increased approximately $36 million. These higher revenues are offset by higher fuel and purchased power expenses and, therefore, have no net effect on earnings. Performance revenues increased $14.5 million as Pilgrim Station operated at a higher capacity in 1996. Retail kWh sales increased 2.8% in 1996, primarily due to the positive economic impacts on our commercial customers.

Demand side management (DSM) revenues decreased primarily due to a decline in current DSM program expenditures.

The primary reason for the decrease in wholesale revenues is due to Pilgrim contract customer revenues. These revenues decreased despite increased kWh sales due to lower operations and maintenance expense related to Pilgrim Station. Pilgrim contract customers are billed for their proportionate share of the unit's costs.

Net short-term sales and other revenues increased $11.8 million. Despite lower kWh sales, short-term sales revenues increased approximately $6 million due to higher fuel prices. Revenues from short-term sales result in a corresponding reduction to future fuel and purchased power billings to retail customers and, therefore, have no net effect on earnings. This increase also reflects an increase in revenue from non-electric sources in 1996.

Operating expenses

Fuel and purchased power expenses increased $53.1 million. Fuel expense increased, despite a slight decrease in company generation, due to significantly higher oil and natural gas prices. Purchased power expense reflects a higher volume of energy purchases and an overall increase in energy prices. These increases were partially offset by the timing effect of fuel and purchased power cost recovery. Fuel and purchased power expenses are substantially recoverable through fuel and purchased power revenues.

Operations and maintenance expense decreased $40.8 million primarily due to lower labor costs resulting from our 1995 restructuring and the continuing cost control efforts of each of our business units. In addition, the amortization of deferred nuclear outage costs decreased $9 million. As discussed in Note B to the Consolidated Financial Statements, in the third quarter of 1995 we made a retroactive change to the amortization period of these deferred costs from five years to two years, consistent with the two-year cycle between refueling outages at Pilgrim Station.

The 1995 operating expenses reflect a $34 million nonrecurring charge related to our corporate restructuring. Refer to Note F to the Consolidated Financial Statements for additional information regarding our 1995 restructuring.

Depreciation and amortization increased $32.2 million. The increase is primarily the result of a change in the estimated remaining economic lives of our Mystic 4, 5 and 6 fossil generating units in the second quarter of 1996, retroactive to the beginning of the year, and an increase in the depreciable plant balance. The change in estimated economic lives of Mystic 4, 5 and 6 resulted in a $22 million increase in depreciation expense for the year.

The decrease in DSM programs expense reflects the decline in current DSM program expenditures.

The increase in income taxes is due to higher net income and a higher effective tax rate in 1996. The effective tax rate in 1996 is 38.2% versus 37.1% in 1995.

Interest charges

Interest on long-term debt decreased due to the maturity of $100 million 8 7/8% debentures in December 1995 and $100 million 5 1/8% debentures in March 1996. These decreases were partially offset by the issuance of $125 million 7.80% debentures in May 1995 which were outstanding for all of 1996. Other interest charges increased due to an increase in interest on short-term debt caused by the higher average short-term debt level partially offset by a lower average short-term borrowing rate. The short-term debt balance increased as a result of the debenture maturities and the redemption of $4 million of preferred stock in 1996. AFUDC decreased due to lower overall construction activity during 1996, shorter construction periods, and lower short-term interest rates.

Electric Sales and Revenues

Electric sales

Retail kWh sales increased 0.8% in 1997. This was primarily attributable to the commercial sector. The commercial increase reflects the impact of a continued strong economy in the Boston area and very warm temperatures in June and July and cooler than normal temperatures in the fourth quarter. Hotel occupancy rates and non-manufacturing employment continued to increase in 1997. The commercial sector represents approximately 50% of our electric operating revenues. Residential revenues, which represent 27% of electric revenues, were also positively impacted by the weather. These positive impacts were offset by milder winter weather in the first quarter of 1997 and declines in manufacturing employment affecting the industrial sector. In addition, revenues in 1996 reflect one more day of sales due to the leap year. The industrial sector represents only 9% of our electric operating revenues. Total kWh sales increased 3.1% as a result of the continued reduction in available nuclear energy supply in New England. This reduction, combined with an increase in our fossil generation allowed for increased sales to the power exchange.

The 2.8% increase in 1996 retail kWh sales was primarily due to the positive effect on commercial customers of the strong economy in our retail service territory. Residential sales decreased slightly primarily due to overall milder than normal weather conditions. Industrial sales remained relatively flat. Total kWh sales, including wholesale, increased 3.3%. The increase in wholesale sales was primarily due to higher sales to our Pilgrim contract customers as the plant was operating for substantially all of 1996. In addition, sales to our municipal customers increased due to a reduction in available energy supply in New England.

Electric revenues

As discussed in the Electric Utility Industry Restructuring section, our delivery business will provide Standard Offer customers service at rates designed to give an average 10% savings upon the retail access date. As part of the recently passed restructuring legislation in Massachusetts, these customers are to realize an additional 5% average savings, after an adjustment for inflation, by September 1, 1999. We expect to meet this additional rate reduction as a result of the proceeds received from the divestiture of our fossil generating assets and potential securitization or refinancing of our stranded costs. Under our settlement agreement, the aggregate amount of our transition charge is reduced by the net proceeds from fossil divestiture.

Under the settlement agreement, the annual performance adjustment charge ceases and our cost recovery mechanism for Pilgrim Station changes as of the retail access date. Approximately 25% of the operations and capital costs, including a return on investment, will continue to be collected under wholesale life of the unit contracts. The remaining output will be sold in the competitive energy market. Through December 31, 2000, we will share 25% of any profit or loss from the sale of Pilgrim's output with distribution customers through the transition charge. In addition, we will obtain transition payments up to a maximum of $23 million per year depending on the level of costs incurred for property taxes, insurance, regulatory fees and security requirements.

Beginning upon the retail access date, the rates of our distribution business will remain unchanged through December 31, 2000, subject to a minimum and maximum return on average common equity (ROE). We will be required to file with the DTE a computation supporting the ROE of our distribution business after each calendar year. The ROE is subject to a floor of 6% and a ceiling of 11.75%. If the ROE is below 6%, we are authorized to add a surcharge to distribution rates in order to achieve the 6% floor. If the ROE is above 11%, we are required to adjust distribution rates by an amount necessary to reduce the calculated ROE between 11% and 12.5% by 50%, and a return above 12.5% by 100%. No adjustment is made if the ROE is between 6% and 11%. The cost of providing transmission service to distribution customers will be recovered on a fully reconciling basis.

Liquidity

We ordinarily meet most of our cash requirements for plant expenditures with internally generated funds. These funds are cash flows from operating activities, adjusted to exclude changes in working capital and the payment of dividends. During 1997, 1996 and 1995 our internal generation of cash provided 211%, 177% and 102%, respectively of our plant expenditures. The capital spending level, excluding nuclear fuel, forecasted for 1998 is $265 million which includes amounts for utility plant and the capital requirements of our nonutility ventures. This spending level also includes the 1998 portion of business system replacements discussed below. The capital spending level over the next five years is forecasted to be approximately $940 million. In addition to capital expenditures, we have debt and preferred stock payment requirements of $103.6 million in 1998 and 1999, $168.6 million in 2000, $53.6 million in 2001 and $3.6 million in 2002.

We supplement our internally generated funds as needed, primarily through the issuance of short-term commercial paper and bank borrowings. We have authority from the FERC to issue up to $350 million of short-term debt. We also 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, 1997, we had $137 million of short-term debt outstanding, none of which was incurred under the revolving credit agreement. We have $220 million remaining under our approved long-term financing plan with the DTE which is available through 1998. Proceeds from issuances under this plan are to be used to refinance short and long-term securities and to fund capital expenditures. Refer to Notes I and J to the Consolidated Financial Statements for additional information relating to our financing activities.

At December 31, 1997, BETG had $7.5 million outstanding under a revolving credit agreement. The purpose of this line is to fund its capital requirements above our $45 million limited investment. This debt will be refinanced upon the formation of BEC Energy.

We anticipate using the sale proceeds from our pending fossil divestiture to adjust our capital structure.

Year 2000 Computer Issue

The year 2000 computer issue is the result of programs written using two digits instead of four to define an applicable year. Consequently, these programs will not properly recognize calendar dates beginning in the year 2000. This could cause computers to shut down or yield incorrect results.

We have developed a plan to address the year 2000 issue that includes modification of certain applications and replacement of systems that are not year 2000 compliant. The cost associated with modification of existing applications will be expensed as incurred. In addition, we have made a decision to use this opportunity to upgrade some of our less efficient centralized business systems. The full replacement costs associated with these systems will be capitalized and amortized over future periods. The total cost of the year 2000 project is expected to be funded through internally generated funds. We anticipate completion of the year 2000 project in the third quarter of 1999.

Other Matters

Environmental

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

We currently own or operate approximately 30 properties where oil or hazardous materials were previously spilled or released. We also continue to face possible liability as a potentially responsible party in the cleanup of six multi-party hazardous waste sites in Massachusetts and other states where we are alleged to have generated, transported or disposed of hazardous waste at the sites. Refer to Note L.6. to the Consolidated Financial Statements for more information regarding hazardous waste issues.

The Accounting Standards Executive Committee of the American Institute of Certified Public Accountants issued Statement of Position 96-1, Environmental Remediation Liabilities (SOP 96-1), effective in 1997. This statement contains authoritative guidance on specific accounting issues related to the recognition, measurement, display and disclosure of environmental remediation liabilities. It requires that an accrual for environmental liabilities include estimates of the costs of compensation and benefits for those employees expected to devote a significant amount of time directly to that effort. SOP 96-1 had no material effect on our financial position or results of operations during 1997.

Uncertainties continue to exist with respect to the disposal of both spent nuclear fuel and low-level radioactive waste (LLW) resulting from the operation of Pilgrim Station. The United States Department of Energy (DOE) is responsible for the ultimate disposal of spent nuclear fuel; however, uncertainties regarding the DOE's schedule of acceptance of spent fuel for disposal continue to exist. In 1995 we regained access to the LLW disposal facility located in Barnwell, South Carolina. Refer to Note E to the Consolidated Financial Statements for further discussion regarding nuclear decommissioning and waste disposal.

The 1990 Clean Air Act Amendments (CAAA) require a significant reduction in nationwide emissions of sulfur dioxide from fossil generating units. Other provisions of the CAAA involve limitations on emissions of nitrogen oxides from existing generating units. As discussed in the Divestiture of Fossil Generating Assets section, we have signed an agreement with Sithe Energies for the sale of our fossil generating assets. If regulatory approval is not obtained or is delayed, we could continue to operate these units subject to the provisions of these amendments. We currently meet the standards of the CAAA and, depending on the outcome of certain Massachusetts Department of Environmental Protection air quality modeling studies, our generating units could continue to operate through at least 1999 before additional emission reductions would be required.

Public concern continues regarding electromagnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Such concerns have included the possibility of adverse health effects caused by EMF as well as perceived effects on property values. Some scientific reviews conducted to date have suggested associations between EMF and potential health effects, while other studies have not substantiated such associations. The National Research Council previously reported that there is no conclusive evidence that exposure to EMF from power lines and appliances presents a health hazard. The panel of scientists, working with the National Academy of Sciences, report that more than 500 studies over the last several years have produced no proof that EMF causes leukemia or other cancers or harms human health in other ways. We continue to support 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 in proceedings before regulators or in requests for legislation or regulatory standards concerning EMF levels. We have addressed issues relative to EMF in various legal and regulatory proceedings and in discussions with customers and other concerned persons; however, to date we have not been significantly affected by these developments. We continue to monitor all aspects of the EMF issue.

Litigation

In October 1997, the DTE opened a proceeding to investigate our compliance with the 1993 order which permitted the formation of BETG and authorized us to invest up to $45 million in unregulated activities. We are unable to determine the ultimate outcome of this proceeding or its impact on our operations.

We were named as a party in lawsuits by Subaru of New England, Inc. and Subaru Distributors Corporation. The plaintiffs claimed certain automobiles stored on lots in South Boston suffered pitting damage caused by emissions from our New Boston Station generating unit. In 1997 we settled both lawsuits. Neither settlement had a material impact on our consolidated results of operations or financial position.

Refer to Note L.8. to the Consolidated Financial Statements for more information on other legal matters in which we are involved.

Industry restructuring legal proceedings/referendum campaign

The DTE order approving our settlement agreement has been appealed by certain parties to the Massachusetts Supreme Judicial Court. In addition, along with other Massachusetts investor owned utilities, we have been named as a defendant in a class action suit seeking to declare certain provisions of the Massachusetts electric industry restructuring legislation unconstitutional. We are currently unable to determine the outcome of these proceedings or their impact on us.

Opponents of the electric industry restructuring legislation that was enacted in November 1997 have mounted a referendum campaign to repeal that law. A coalition of business, industry and public interest groups that supported the legislation, along with the electric utility industry, is opposed to the referendum and is prepared to mount an aggressive campaign to defeat it. We are currently unable to predict the eventual outcome of this referendum or its impact on us.

Safe harbor cautionary statement

We occasionally make forward-looking statements such as forecasts and projections of expected future performance or statements of our plans and objectives. These forward-looking statements may be contained in filings with the Securities and Exchange Commission, press releases and oral statements. Actual results could potentially differ materially from these statements. Therefore, no assurances can be given that the outcomes stated in such forward-looking statements and estimates will be achieved.

The preceding sections include certain forward-looking statements about the effects of the industry restructuring process and our related settlement agreement, the divestiture of our fossil generating assets, operating results, year 2000 and environmental and legal issues.

The effects of electric utility industry restructuring could differ from our expectations. This could occur as regulatory decisions and negotiated settlements between utilities and intervenors are finalized. In addition, the development of a competitive electric generation market, the impacts of actual electric supply and demand in New England and further legislative action may affect the ultimate results of the industry restructuring and our settlement agreement.

The divestiture plan could differ from our expectations. This could occur if required regulatory approvals are delayed or not obtained.

The impacts of our continued cost control procedures on our operating results could differ from our expectations. The effects of changes in economic conditions, tax rates, interest rates, technology and the prices and availability of operating supplies could materially affect our projected operating results.

The timing and total costs related to our year 2000 plan could differ from our expectations. Factors that may cause such differences include the ability to locate and correct all relevant computer codes and the availability of personnel trained in this area. In addition, we cannot predict the nature or impact on operations of third party noncompliance.

The impacts of various environmental and legal issues could differ from our expectations. New regulations or changes to existing regulations could impose additional operating requirements or liabilities other than expected. The effects of changes in specific hazardous waste site conditions and cleanup technology could affect our estimated cleanup liabilities. The impacts of changes in available information and circumstances regarding legal issues could affect our estimated litigation costs.

Consolidated Statements of Income

(in thousands, except earnings per share)	1997	1996	1995
		years ended December 31,	
Operating revenues	$1,776,233	$1,666,303	$1,628,503
Operating expenses:			
Fuel and purchased power	679,131	588,893	535,806
Operations and maintenance	414,779	417,372	458,196
Restructuring costs	0	0	34,000
Depreciation and amortization	188,687	185,494	153,339
Demand side management programs	29,790	30,825	45,125
Taxes-property and other	107,975	107,086	106,361
Income taxes	95,021	88,703	68,276
Total operating expenses	1,515,383	1,418,373	1,401,103
Operating income	260,850	247,930	227,400
Other income (expense), net	(10,498)	698	(575)
Operating and other income	250,352	248,628	226,825
Interest charges:			
Long-term debt	92,489	94,823	106,640
Other	14,410	14,551	12,642
Allowance for borrowed funds used during construction	(1,189)	(2,292)	(4,767)
Total interest charges	105,710	107,082	114,515
Net income	144,642	141,546	112,310
Preferred stock dividends	13,149	15,365	15,571
Earnings available for common shareholders	$ 131,493	$ 126,181	$ 96,739
Weighted average common shares outstanding	48,515	48,265	46,592
Earnings per share of common stock-basic and diluted	$ 2.71	$ 2.61	$ 2.08

Consolidated Statements of Retained Earnings

(in thousands)	1997	1996	1995
		years ended December 31,	
Balance at the beginning of the year	$ 292,191	$ 257,749	$ 247,409
Net income	144,642	141,546	112,310
Subtotal	436,833	399,295	359,719
Dividends declared:			
Preferred stock	13,149	15,365	15,571
Common stock	91,208	90,834	86,399
Subtotal	104,357	106,199	101,970
Provision for preferred stock redemption and issuance costs (a)	3,674	905	0
Balance at the end of the year	$ 328,802	$ 292,191	$ 257,749

(a) Refer to Note B.7. to the Consolidated Financial Statements.

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

Consolidated Balance Sheets

(in thousands)		1997		December 31, 1996
Assets				
Utility plant in service, at original cost	$ 4,457,868		$ 4,387,887	
Less: accumulated depreciation	1,713,079	$ 2,744,789	1,550,317	$ 2,837,570
Nuclear fuel	351,722		351,453	
Less: accumulated amortization	283,787	67,935	268,509	82,944
Construction work in progress		41,403		30,376
Net utility plant		2,854,127		2,950,890
Nuclear decommissioning trust		151,634		132,076
Equity investments		35,455		28,752
Other investments		7,107		7,630
Current assets:				
Cash and cash equivalents	4,140		5,651	
Accounts receivable	192,220		233,024	
Accrued unbilled revenues	30,048		34,922	
Fuel, materials and supplies, at average cost	60,834		57,075	
Prepaids and other	31,283	318,525	45,146	375,818
Deferred debits:				
Regulatory assets		220,403		202,026
Other		35,096		32,099
Total assets		$ 3,622,347		$ 3,729,291
Capitalization and Liabilities				
Common stock equity		$ 1,073,454		$ 1,036,424
Cumulative preferred stock		161,093		201,419
Long-term debt		1,057,076		1,058,644
Current liabilities:				
Long-term debt/preferred stock due within one year	$ 102,667		$ 102,667	
Notes payable	137,013		201,454	
Accounts payable	87,015		134,083	
Accrued interest	24,289		24,378	
Dividends payable	24,748		25,343	
Other	128,061	503,793	115,812	603,737
Deferred credits:				
Accumulated deferred income taxes		485,738		498,718
Accumulated deferred investment tax credits		60,736		58,899
Nuclear decommissioning liability		155,182		133,388
Power contracts		71,445		88,963
Other		53,830		49,099
Commitments and contingencies				
Total capitalization and liabilities		$ 3,622,347		$ 3,729,291

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

Consolidated Statements of Cash Flows

(in thousands)	1997	1996	1995
		years ended December 31,	
Operating activities:			
Net income	$ 144,642	$ 141,546	$ 112,310
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	223,529	228,259	202,294
Deferred income taxes and investment tax credits	(21,664)	(4,057)	(25,193)
Allowance for borrowed funds used during construction	(1,189)	(2,292)	(4,767)
Net changes in:			
Accounts receivable and accrued unbilled revenues	45,678	(11,719)	(34,626)
Fuel, materials and supplies	(5,486)	(2,171)	7,202
Accounts payable	(47,068)	609	2,978
Other current assets and liabilities	25,428	(44,514)	26,485
Other, net	(4,640)	50,815	26,993
Net cash provided by operating activities	359,230	356,476	313,676
Investing activities:			
Plant expenditures (excluding AFUDC)	(114,110)	(145,347)	(180,822)
Nuclear fuel expenditures	(4,089)	(52,967)	(13,621)
Investments in joint ventures	(7,859)	(5,698)	0
Other investments	(19,830)	(28,616)	(19,005)
Net cash used in investing activities	(145,888)	(232,628)	(213,448)
Financing activities:			
Issuances:			
Common stock	144	12,559	64,888
Long-term debt	100,000	0	125,000
Redemptions:			
Preferred stock	(44,000)	(4,000)	(2,000)
Long-term debt	(101,600)	(101,600)	(100,600)
Net change in notes payable	(64,441)	75,013	(88,345)
Dividends paid	(104,956)	(106,010)	(100,152)
Net cash used in financing activities	(214,853)	(124,038)	(101,209)
Net decrease in cash and cash equivalents	(1,511)	(190)	(981)
Cash and cash equivalents at the beginning of the year	5,651	5,841	6,822
Cash and cash equivalents at the end of the year	$ 4,140	$ 5,651	$ 5,841

Supplemental disclosures of cash flow information:

Cash paid during the year for:			
Interest, net of amounts capitalized	$ 100,795	$ 100,810	$ 104,011
Income taxes	$ 99,326	$ 98,668	$ 96,180

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

Notes to Consolidated Financial Statements

Note A. Nature of Operations

Boston Edison Company (the Company) is an investor-owned regulated public utility operating in the energy, energy services and telecommunications business. This includes the generation, purchase, transmission, distribution and sale of electric energy and the development and implementation of electric demand side management programs. A portion of our generation is produced by our wholly owned nuclear generating unit, Pilgrim Nuclear Power Station. We supply electricity at retail to an area of 590 square miles, including the city of Boston and 39 surrounding cities and towns. We also supply electricity at wholesale for resale to other utilities and municipal electric departments. Electric operating revenues were 88% retail and 12% wholesale in 1997. We also conduct unregulated activities through our wholly owned subsidiary, Boston Energy Technology Group (BETG).

Through BETG and its subsidiaries, we are engaged in certain nonutility businesses, including energy utilization and conservation, construction management and district energy. BETG has a joint venture with RCN Telecom Services, Inc. (RCN) that provides certain telecommunications-related services. The limited liability company (LLC) formed from this joint venture is owned 51% by RCN and 49% by BETG, with RCN having the day-to-day management responsibility. BETG also has a joint venture with Williams Energy Services Company (WESCO). This joint venture markets electricity, natural gas and energy-related services to retail customers in the six New England states. BETG and WESCO each own 50% of this LLC, EnergyVision.

We are currently awaiting a decision from the Massachusetts Department of Telecommunications and Energy (DTE), formerly the Department of Public Utilities, regarding our plan to form a holding company structure. This structure will clearly separate our regulated and unregulated lines of business. Through our holding company, BEC Energy, we will seek ways to expand our customer base. After the corporate reorganization, Boston Edison will be a wholly owned subsidiary of BEC Energy. BETG will cease being a subsidiary of Boston Edison and become a wholly owned subsidiary of BEC Energy. The common shareholders of Boston Edison will become shareholders of BEC Energy. The existing debt and preferred stock of Boston Edison will remain obligations of the regulated utility business.

Refer also to Note C to these Consolidated Financial Statements for changes in the nature of our operations as a result of the electric utility industry restructuring and our related settlement agreement.

Note B. 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 (HEEC) and BETG. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the prior year data to conform with the current presentation.

We follow accounting policies prescribed by the Federal Energy Regulatory Commission (FERC) and the DTE. We are also subject to the accounting and reporting requirements of the Securities and Exchange Commission. The consolidated financial statements conform with generally accepted accounting principles (GAAP). As a rate-regulated company we have been subject to Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71), under GAAP. The application of SFAS 71 results in differences in the timing of recognition of certain expenses from that of other businesses and industries. As a result of the recently passed Massachusetts electric industry restructuring legislation and the DTE order regarding our related settlement agreement, as of December 31, 1997, we are no longer applying the provisions of SFAS 71 to our generation business. Our distribution business remains subject to rate-regulation and continues to meet the criteria for application of SFAS 71. Refer to Note C to these Consolidated Financial Statements for more information on the accounting implications of the electric utility industry restructuring.

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

2. Revenues

We record estimates of retail base revenues for electricity used by our customers but not yet billed at the end of each accounting period.

3. Forecasted Fuel and Purchased Power Rates

The rate charged to retail customers for fuel and purchased power allows for fuel and purchased power costs which are not included in our base rates to be billed to customers using a forecasted rate. The difference between actual costs and the amounts billed to customers is recorded as an adjustment to fuel and purchased power expenses and is included in accounts receivable on the consolidated balance sheet until subsequent rates are adjusted.

4. Utility Plant

Utility plant is stated at original cost of construction. The costs of replacements of property units are capitalized. Maintenance and repairs and replacements of minor items are expensed as incurred. The original cost of property retired, net of salvage value, and the related costs of removal are charged to accumulated depreciation.

5. Depreciation and Nuclear Fuel Amortization

Depreciation of our utility plant is computed on a straight-line basis using composite rates based on the estimated useful lives of the various classes of property. Excluding the effect of the adjustment discussed below, the overall composite depreciation rates were 3.30%, 3.33% and 3.28% in 1997, 1996 and 1995, respectively.

Upon the completion of a review of our electric generating units, we determined that our oldest and least efficient fossil units (Mystic 4, 5 and 6) were unlikely to provide competitively-priced power beyond the year 2000. Therefore we revised the estimated remaining economic lives of these units to five years in 1996.

The cost of decommissioning Pilgrim Station is excluded from our depreciation rates. Refer to Note E to these Consolidated Financial Statements for a discussion of nuclear decommissioning. 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 spent nuclear fuel and for assessments for the decontamination and decommissioning of United States Department of Energy nuclear enrichment facilities. These costs are recovered from our customers through fuel rates.

6. Deferred Nuclear Outage Costs

We defer the incremental costs associated with nuclear refueling outages when incurred and amortize them over Pilgrim Station's operating cycle. In 1995 we changed the amortization period from five years to two years. The two-year amortization period is consistent with the two-year cycle between nuclear refueling outages at Pilgrim Station.

7. Costs Associated with Issuance and Redemption of Debt and Preferred Stock

Consistent with our recovery in electric rates, we defer discounts, redemption premiums and related costs associated with the redemption and issuance of long-term debt and preferred stock. The costs related to long-term debt are recognized as an addition to interest expense over the life of the original or replacement debt. Beginning in 1996, consistent with an accounting order received from the FERC, we reflect costs related to preferred stock redemptions and issuances as a direct reduction to retained earnings upon redemption or over the average life of the replacement preferred stock series as applicable.

8. Allowance for Borrowed Funds Used During Construction (AFUDC)

AFUDC represents the estimated costs to finance utility plant construction. In accordance with regulatory accounting, AFUDC is included as a cost of utility plant and a reduction of current interest charges. Although AFUDC is not a current source of cash income, the costs are recovered from customers over the service life of the related plant in the form of increased revenues collected as a result of higher depreciation expense. Our AFUDC rates in 1997, 1996 and 1995 were 6.04%, 5.87% and 6.35%, respectively, and represented only the cost of short-term debt.

9. Cash and Cash Equivalents

Cash and cash equivalents are comprised of highly liquid securities with maturities of 90 days or less when purchased. Outstanding checks are included in cash and accounts payable until they are presented for payment.

10. Allowance for Doubtful Accounts

Our accounts receivable are substantially 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.

11. Regulatory Assets

Regulatory assets represent costs incurred which are expected to be collected from customers through future charges in accordance with agreements with our regulators. These costs are expensed when the corresponding revenues are received in order to appropriately match revenues and expenses. The majority of these costs is currently being recovered from customers over varying time periods. Refer to Note C to these Consolidated Financial Statements for information regarding the recovery of regulatory assets related to our generation business.

Regulatory assets consisted of the following:

		December 31,
	1997	1996
Fossil divestiture	$ 21,248	$ 0
Power contracts	71,445	88,963
Income taxes, net	51,096	47,483
Redemption premiums	27,019	31,052
Postretirement benefits costs	22,441	15,009
Decontamination and decommissioning	12,282	13,190
Nuclear outage costs	10,160	3,432
Other	4,712	2,897
	$ 220,403	$ 202,026

12. Earnings Per Share of Common Stock

Basic earnings per share (EPS) of common stock is calculated by dividing net income, after the payment of preferred stock dividends, by the weighted average common shares outstanding during the year. Statement of Financial Accounting Standards No. 128, Earnings per Share, requires the disclosure of diluted EPS effective for periods ending after December 15, 1997. Diluted EPS is similar to the computation of basic EPS except that the weighted average common shares is increased to include the number of dilutive potential common shares. Diluted EPS, which includes the effect of deferred (nonvested) shares and stock options granted under the Stock Incentive Plan in the calculation of weighted average common shares, is the same as basic EPS displayed on the consolidated statement of income.

Note C. Electric Utility Industry Restructuring

1. Accounting Implications

Under the traditional revenue requirements model, our electric rates have been based on the cost of providing electric service. As such, we have been subject to certain accounting standards that are not applicable to other businesses and industries in general. The application of SFAS 71 requires us to defer the recognition of certain costs when incurred if future rate recovery of these costs is expected. Based on a consensus reached by the Emerging Issues Task Force (EITF) regarding specific issues raised related to the application of SFAS 71, we have determined that, as of December 31, 1997, the provisions of SFAS 71 no longer apply to the generation portion of our business. In its consensus, the EITF determined that when deregulation legislation is passed and regulatory actions have taken place providing sufficient detail for an enterprise to reasonably determine how the transition plan will affect the separable portion of its business being deregulated, the enterprise should stop applying SFAS 71 to that portion of its business. On January 28, 1998, the DTE approved our restructuring settlement agreement that was filed in July 1997. The DTE found that the settlement agreement substantially complied or was consistent with key provisions of a Massachusetts law enacted in November 1997 establishing a comprehensive framework for the restructuring of our industry. The EITF further determined that book values of assets and liabilities originating in the separable portion of the business no longer subject to rate-regulation should be evaluated on the basis of where the regulated cash flows to realize and settle them will be derived. Net utility plant and other related assets on our consolidated balance sheet as of December 31, 1997 include approximately $700 million related to nuclear generation and approximately $450 million related to fossil generation. As part of our settlement agreement, approximately 75% of these nuclear assets are fully recoverable through the non-bypassable transition charge of our distribution business which continues to be subject to rate-regulation. The remaining 25% will be collected under Pilgrim's wholesale life of the unit contracts. These contracts continue to be regulated by the FERC and are not impacted by our settlement agreement. These fossil assets will be recovered from the proceeds from their sale as discussed in part 2 below.

The implementation of our approved settlement agreement has certain accounting implications. The highlights of these include:

Depreciation

The composite depreciation rate for distribution utility plant increases from 2.38% to 2.98% as of March 1, 1998 (the retail access date).

Generation related plant and regulatory assets

Plant and regulatory assets related to our generation business, except for those related to Pilgrim's wholesale life of the unit contracts, will be recovered through the transition charge. This recovery, which includes a return, will occur over a twelve-year period.

Storm fund

Under the settlement agreement, we are authorized to establish a storm contingency fund to use for the incremental costs of any major storm (in excess of $1 million). The settlement required that we initially establish the fund with $8 million of proceeds received from the sale of Clean Air Act emission allowances. As costs are charged against the fund, the balance will be restored to the original level from distribution charges up to a maximum of $3 million per year.

Fuel and purchased power charge

The fuel and purchased power charge ceases as of the retail access date. Net remaining over or under collection of fuel and purchased power costs will be reflected in future customer billings.

Standard offer charge

Customers will have the option of continuing to buy power from our electric delivery business at "Standard Offer" prices as of the retail access date. The Standard Offer charge begins at 2.8 cents at retail access and increases to 5.1 cents by 2004. The cost of providing Standard Offer service, which includes fuel and purchased power costs, will be recovered from Standard Offer customers on a fully reconciling basis.

Distribution and transmission charges

Distribution rates will be subject to a minimum and maximum return on average common equity (ROE) through December 31, 2000. The ROE is subject to a floor of 6% and a ceiling of 11.75%. If the ROE is below 6%, we are authorized to add a surcharge to distribution rates in order to achieve the 6% floor. If the ROE is above 11%, we are required to adjust distribution rates by an amount necessary to reduce the calculated ROE between 11% and 12.5% by 50%, and a return above 12.5% by 100%. No adjustment is made if the ROE is between 6% and 11%. In addition, distribution rates will be adjusted for any changes in tax laws or accounting principles that result in a change in our costs of more than $1 million. The cost of providing transmission service to distribution customers will be recovered on a fully reconciling basis.

Nuclear generation

Under the settlement agreement, the annual performance adjustment charge ceases and our cost recovery mechanism for Pilgrim Station changes as of the retail access date. Approximately 25% of the operations and capital costs, including a return on investment, will continue to be collected under wholesale life of the unit contracts. The remaining output will be sold in the competitive energy market. Through December 31, 2000, we will share 25% of any profit or loss from the sale of Pilgrim's output with distribution customers through the transition charge. In addition, we will obtain transition payments up to a maximum of $23 million per year depending on the level of costs incurred for property taxes, insurance, regulatory fees and security requirements.

Nuclear decommissioning

Approximately 25% of Pilgrim's decommissioning costs will continue to be collected under wholesale life of the unit contracts. The remaining portion will be recovered through the transition charge. Amounts collected for decommissioning will be adjusted as decommissioning cost studies are updated. Refer to Note E to these Consolidated Financial Statements for more information on nuclear decommissioning costs.

2. Divestiture of Fossil Generating Assets

Included in our settlement agreement is a provision for the divestiture of our fossil generating assets. On December 10, 1997, we entered into a purchase and sale agreement with Sithe Energies, Inc., a privately-held company headquartered in New York, to purchase our non-nuclear generating assets. The proceeds from the sale of these assets will be $657 million. The net book value of these assets at December 31, 1997 is approximately $450 million. Included in the purchase price, Sithe Energies will pay $121 million to us in connection with a six-month transitional power sales agreement under which we will continue to buy power from the generating plants. Sithe Energies will also be responsible for obligations resulting from the recently enacted utility restructuring legislation for property tax payments to communities with non-nuclear power plants.

In July 1997, we reached an agreement with our field service union that requires the buyer of our fossil generating assets to recognize and continue to honor the provisions of the union's current collective bargaining agreement through the end of its term, May 2000. As part of a package offered to employees affected by the fossil divestiture, all eligible fossil and designated fossil support employees age 55 or older with at least 10 years of service, or age 65 by July 1, 1998, were offered unreduced retirement and transition benefits under a voluntary early retirement program (VERP). Under this program, 40 people elected to retire. Retirement dates are expected to be the first of the month following the transfer of ownership of our fossil generating assets. Severance programs were offered to management and field service union employees affected by the fossil divestiture that did not elect or were ineligible to retire under the VERP. These severance benefits include salary payments, education/retraining allowances and outplacement services. It is anticipated that 48 employees will receive severance benefits under these programs.

The estimated costs associated with the VERP and severance programs is approximately $21 million including the effects on the retirement, life and dental plans. Severance and employee retraining costs related to the divestiture are recoverable through the distribution transition charge under our settlement agreement. Therefore, we have established an offsetting regulatory asset for these obligations on our consolidated balance sheet at December 31, 1997.

3. Nuclear Asset Impairment

As part of the settlement agreement, we recover our net investment in Pilgrim Station as of December 31, 1995 (adjusted for depreciation through 1997) through the distribution transition charge. Under the terms of the settlement agreement, we must perform a market valuation of Pilgrim by 2002. Upon acceptance of the valuation by the DTE, the resulting dollar amount, net of prudently incurred post-1995 investments in the plant, will reduce amounts collectible through the transition charge. If the valuation is not sufficient to allow for the recovery of these investments, we will seek their recovery through the transition charge. Due to the market pressures facing us, the ultimate recovery of these assets is not certain. Therefore, we reduced our investment in Pilgrim by the $13 million invested in the plant since January 1, 1996 as an impairment loss under Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of (SFAS 121). An after tax charge of approximately $8 million due to this reduction was recorded to non-operating expense on our consolidated statement of income in the fourth quarter of 1997. A similar uncertainty does not exist for the ultimate recovery of the fossil generating assets as the sale proceeds agreed to in the purchase and sale agreement with Sithe Energies exceeds the net book value of these assets.

Note D. Income Taxes

Income taxes are accounted for in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). SFAS 109 requires the recognition of deferred tax assets and liabilities 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 net regulatory assets of $51.1 million and $47.5 million and corresponding net increases in accumulated deferred income taxes as of December 31, 1997, and December 31, 1996, respectively. The regulatory assets represent the additional future revenues to be collected from customers for deferred income taxes.

Accumulated deferred income taxes consisted of the following:

		December 31,
(in thousands)	1997	1996
Deferred tax liabilities:		
Plant-related	$ 535,460	$ 532,390
Other	79,930	95,642
	615,390	628,032
Deferred tax assets:		
Plant-related	11,926	8,406
Investment tax credits	33,125	38,005
Other	84,601	82,903
	129,652	129,314
Net accumulated deferred income taxes	$ 485,738	$ 498,718

No valuation allowances for deferred tax assets are deemed necessary.

Previously deferred investment tax credits are amortized over the estimated lives of the property giving rise to the credits.

Components of income tax expense were as follows:

(in thousands)	1997	1996	1995
			years ended December 31,
Current income tax expense	$ 116,685	$ 92,760	$ 93,469
Deferred income tax expense	(14,104)	14	(21,115)
Investment tax credit amortization	(7,560)	(4,071)	(4,078)
Income taxes charged to operations	95,021	88,703	68,276
Taxes on other income:			
Current	(12,566)	(721)	(1,729)
Total income tax expense	$ 82,455	$ 87,982	$ 66,547

The effective income tax rates reflected in the consolidated financial statements and the reasons for their differences from the statutory federal income tax rate were as follows:

	1997	1996	1995
Statutory tax rate	35.0%	35.0%	35.0%
State income tax, net of federal income tax benefit	4.5	4.3	4.3
Investment tax credit amortization	(3.3)	(1.8)	(2.3)
Other	0.1	0.7	0.1
Effective tax rate	36.3%	38.2%	37.1%

The 1997 effective tax rate declined by 0.8% as a result of the favorable outcome of an Internal Revenue Service appeal related to investment tax credits.

Note E. Nuclear Decommissioning and Nuclear Waste Disposal

1. Nuclear Decommissioning

When Pilgrim Station's operating license expires in 2012 we will be required to decommission the plant. Decommissioning means to remove nuclear facilities from service safely and reduce residual radioactivity to a level that permits termination of the Nuclear Regulatory Commission (NRC) license and release of the property for unrestricted use. We record an estimate of decommissioning costs in depreciation expense on the consolidated statements of income over Pilgrim's expected service life. Decommissioning expense is approximately $14 million per year. The estimate used to determine our annual expense is based on a 1991 study that documents a cost of approximately $328 million to decommission the plant using the "green field" method, which provides for the plant site to be completely restored to its original state. The cost estimate was incorporated in our 1992 retail settlement agreement. We receive recovery of the annual expense through charges to our retail customers and from other utility companies and municipalities which 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 to use for decommissioning and related expenses. The net earnings on the trust funds, which are also restricted, increase the nuclear decommissioning trust balance, thus reducing the amount to be collected from customers.

The 1991 decommissioning study was partially updated for internal planning purposes in order to evaluate the potential impact of long-term spent fuel storage options resulting from delays in the United States Department of Energy (DOE) spent fuel removal program. Refer to part 2 for a discussion of spent fuel removal. The partial update indicated an estimated decommissioning cost of $400 million in 1991 dollars based upon a revised spent fuel removal schedule and utilization of dry spent fuel storage technology. We are in the process of updating this study. No final cost estimate is currently available; however, we continue to monitor DOE spent fuel removal schedules and developments in spent fuel storage technology along with their impact on the decommissioning estimate.

Certain financial reporting considerations related to nuclear decommissioning costs have not been fully resolved. In 1996 the Financial Accounting Standards Board (FASB) issued proposed new rules for accounting for liabilities related to closure and removal of long-lived assets, which include decommissioning of nuclear generating facilities. If these proposed rules are adopted we would be required to retroactively recognize the entire estimated liability for decommissioning costs on the balance sheet, offset by an addition to utility plant. The plant addition would be depreciated over Pilgrim's remaining expected service life. The liability would be measured based on the present value of estimated future cash flows. The cumulative effect of adoption of these proposed rules could result in the recognition of a regulatory asset to be recovered from customers to the extent that the present value difference in the liability between when the liability was incurred and when the rules are adopted exceeds the depreciation expense previously recognized for decommissioning. In addition, trust fund earnings would be reported on the income statement. The FASB recently resumed its deliberations on this project. No date has been set for the issuance of either a final statement or revised proposed rules.

2. Spent Nuclear Fuel

The spent fuel storage facility at Pilgrim Station is expected to provide storage capacity through approximately 2003. We have a license amendment from the NRC to modify the facility to provide sufficient room for spent nuclear fuel generated through the end of Pilgrim's operating license in 2012; however, any further modifications are subject to review by the DTE. We are actively exploring the feasibility of other spent fuel storage facilities and technologies.

Delays in identifying a permanent storage site have continually postponed plans for the DOE's long-term storage and disposal site for spent nuclear fuel. The DOE's current estimate for an available site is 2010. In November 1997, the U.S. Court of Appeals for the District of Columbia Circuit ruled that the lack of an interim storage facility does not excuse the DOE from meeting its contract obligation to begin accepting spent nuclear fuel no later than January 31, 1998. This decision was in response to petitions filed by us and other interested parties seeking declaratory rulings concerning enforcement and remedies for the DOE's failure to accept spent fuel in a timely manner. The court directed the plaintiffs to pursue relief under terms of their contracts with the DOE. Based on this ruling, the DOE may have to pay contract damages if it does not take the spent nuclear fuel as scheduled. Under the Nuclear Waste Policy Act of 1982, it is the ultimate responsibility of the DOE to permanently dispose of spent nuclear fuel. 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. We cannot predict at this time whether or on what schedule the DOE will eventually construct a spent fuel repository or what the effect will be of any delays in such construction.

The DOE recently denied our petition to suspend payments made to the Nuclear Waste Fund based on its interpretation of the U.S. Court of Appeal's decision made in November 1997. The DOE has, however, made an offer to consider amendments to existing contracts to address the hardships the anticipated delay in accepting spent fuel may cause individual contract holders. We continue to monitor this situation and consult with legal counsel as to our next course of action.

3. Low-Level Radioactive Waste

We regained access to low-level radioactive waste (LLW) disposal facilities located in Barnwell, South Carolina, in 1995. This site is currently the only disposal facility available to us. Legislation has been enacted in Massachusetts establishing a regulatory process for managing LLW, including the possible siting, licensing and construction of a disposal facility within the state, or, alternatively, an agreement with one or more other states. Pending the construction of a disposal facility within the state or the adoption by the state of some other LLW management procedure, we will continue to monitor the situation and investigate other available options.

Note F. 1995 Corporate Restructuring

In 1995 we streamlined the corporate organization and reorganized the company into separate business units in order to strengthen our competitiveness in the changing electric energy market. In conjunction with this reorganization we offered enhanced retirement programs and implemented a special severance program to reduce employee staffing levels. Under the enhanced retirement programs 330 employees elected to retire, and 149 employees whose positions were eliminated became eligible for benefits under the special severance program. These programs resulted in a $34 million pre-tax charge ($20.7 million after tax) over the third and fourth quarters of 1995. The charge consisted of $24 million for the retirement programs and $10 million for the severance program.

Note G. Pensions and Other Postretirement Benefits

1. Pensions

We have a defined benefit funded retirement plan with certain contributory features that covers substantially all employees. Benefits are based upon an employee's years of service and highest eligible average compensation during the last ten years of credited employment. Our funding policy is to contribute an amount each year that is not less than the minimum required contribution under federal law or greater than the maximum tax deductible amount. The retirement plan assets consist of equities, bonds, money market funds, insurance contracts and real estate funds.

We also have an unfunded supplemental retirement plan for certain management employees. Benefits under this plan are based upon an employee's years of service and highest eligible average compensation during years of credited employment.

Net pension cost consisted of the following components:

(in thousands)	1997	years ended December 31, 1996	1995
Current service cost - benefits earned	$ 12,625	$ 13,452	$ 11,339
Interest cost on projected benefit obligation	31,537	32,325	31,789
Actual return on plan assets	(60,602)	(40,335)	(72,192)
Net amortization and deferral	33,912	17,064	49,557
Net pension cost	$ 17,472	$ 22,506	$ 20,493

In accordance with our 1992 retail rate settlement agreement we deferred the difference between the net pension cost of the retirement plan and its annual funding amount through 1995. Net pension cost recognized in 1995 was $28 million.

We experienced a high number of employee retirements from 1994 to 1996. A large number of these retirements were as a direct result of our 1995 corporate restructuring. In 1997, a review of the accounting for the pension expense related to the retirements revealed that an adjustment to the pension costs related to these employees was necessary. Therefore, we increased our pension regulatory asset by $8.6 million in 1997 for the adjustment related to the period of our 1992 settlement agreement. The remaining adjustment did not have a material impact on our consolidated results of operations or financial position.

We used the following assumptions for calculating pension cost:

	1997	1996	1995
Discount rate	7.75%	7.25%	8.25%
Expected long-term rate of return on assets	10.00%	10.00%	10.00%
Compensation increase rate	3.90%	3.90%	3.90%

The plans' funded status were as follows:

(in thousands)	1997		December 31, 1996	
	Retirement Plan	Supplemental Retirement Plan	Retirement Plan	Supplemental Retirement Plan
Actuarial present value of accumulated benefit obligation:				
Vested	$ 361,484	$ 8,571	$ 316,101	$ 7,576
Non-vested	10,578	1,192	10,867	943
Total	$ 372,062	$ 9,763	$ 326,968	$ 8,519
Plan assets at fair value	$ 401,182	$ 0	$ 331,299	$ 0
Projected obligation for service rendered to date	(446,360)	(11,076)	(400,561)	(9,199)
Projected benefit obligation in excess of plan assets	(45,178)	(11,076)	(69,262)	(9,199)
Unrecognized prior service cost	9,385	9,736	11,238	9,436
Unrecognized net loss/(gain)	50,673	(27)	78,853	(1,141)
Unrecognized net obligation	5,704	0	7,130	0
Additional minimum liability (a)	0	(8,396)	0	(7,615)
Net pension prepayment/(liability) (b)	$ 20,584	$ (9,763)	$ 27,959	$ (8,519)

(a) Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions (SFAS 87), requires the recognition of an additional minimum liability for the excess of accumulated benefits over the fair value of plan assets and accrued pension costs. In accordance with SFAS 87 we recorded additional minimum liabilities and corresponding intangible assets of $8.4 million and $7.6 million on our consolidated balance sheets at December 31, 1997 and 1996, respectively.

(b) The prepaid pension amount at December 31, 1997 reflects the impact of $8 million related to the fossil workforce reduction as discussed in Note C to these Consolidated Financial Statements.

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

	1997	1996
Discount rate	7.25%	7.75%
Compensation increase rate	4.25%	3.90%

We also provide defined contribution 401(k) plans for substantially all of our employees. We match a portion of employees' voluntary contributions to the plans. We made matching contributions of $8 million in 1997 and 1996 and $9 million in 1995.

2. Other Postretirement Benefits

In addition to pension benefits, we also provide health care and other benefits to our retired employees who meet certain age and years of service eligibility requirements. These postretirement benefits other than pensions (PBOPs) are accounted for in accordance with Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). Our 1992 retail rate settlement agreement provided us with a phase-in to full expense of the PBOP costs incurred under SFAS 106. This settlement agreement allowed us to defer any costs in excess of the specified phase-in amounts to the extent that we funded an external trust. Our funding policy is to generally contribute 100% of PBOP costs to external trusts. Therefore, we recognized $23 million of PBOP costs in 1995 in accordance with the 1992 settlement agreement. Beginning in 1996 we recognized the full PBOP costs incurred under SFAS 106. The net deferred PBOP costs of $15 million resulting from the delayed phase-in are included in regulatory assets as these costs will be recovered from customers in future periods.

Net postretirement benefits cost consisted of the following components:

		years ended December 31,	
(in thousands)	1997	1996	1995
Current service cost - benefits earned	$ 3,543	$ 4,616	$ 3,408
Interest cost on accumulated benefit obligation	17,006	16,815	13,521
Actual return on plan assets	(18,852)	(9,584)	(7,151)
Amortization of transition obligation	9,151	9,151	9,151
Net other amortization and deferral	12,417	5,209	3,017
Net postretirement benefits cost	$ 23,265	$ 26,207	$ 21,946

We used the following assumptions for calculating postretirement benefits cost:

	1997	1996	1995
Discount rate	7.75%	7.25%	8.25%
Expected long-term rate of return on assets	9.00%	9.00%	9.00%
Health care cost trend rate	6.00%	7.00%	7.00%

The health care cost trend rate is assumed to decrease by 1% in 1998 and to remain at 5% in years thereafter. Changes in the health care cost trend rate will affect our cost and obligation amounts. A 1% increase in the assumed health care cost trend rate would increase the total service and interest cost components by 7.4% and would increase the accumulated benefit obligation at December 31, 1997 by 6.6%.

The PBOP program's funded status was as follows:

(in thousands)		December 31, 1997		1996
Trust assets at fair value		$ 103,989		$ 72,702
Accumulated obligation for service rendered to date from:				
Retirees	$ (166,035)		$ (156,694)	
Active employees eligible to retire	(16,484)		(12,644)	
Active employees not eligible to retire	(55,097)	(237,616)	(61,567)	(230,905)
Accumulated benefit obligation in excess of trust assets		(133,627)		(158,203)
Unrecognized prior service cost		(14,128)		(16,274)
Unrecognized net loss		12,916		26,663
Unrecognized transition obligation		127,107		146,413
Net postretirement benefits liability (a)		$ (7,732)		$ (1,401)

(a) The postretirement benefits liability at December 31, 1997 reflects an $8 million additional PBOP obligation related to the fossil workforce reduction as discussed in Note C to these Consolidated Financial Statements.

The weighted average discount rates used to measure the program's year-end funded status were 7.25% in 1997 and 7.75% in 1996. The trust assets consist of equities, bonds and money market funds.

Note H. Stock-Based Compensation

In 1997, we initiated a Stock Incentive Plan (the Plan) which was adopted by the Board of Directors and approved by our stockholders. The Plan permits a variety of stock and stock-based awards, including stock options and deferred (nonvested) stock to be granted to certain key employees. The Plan limits the terms of awards to ten years. Subject to adjustment for stock-splits and similar events, the aggregate number of shares of common stock that may be delivered under the Plan is 2,000,000, including shares issued in lieu of or upon reinvestment of dividends arising from awards. During 1997, we granted 73,820 shares of deferred stock and 298,400 ten-year non-qualified stock options under the Plan. The weighted average grant date fair value of the deferred stock is $27.26. The options were granted at the full market price of the stock on the date of the grant. Both awards vest ratably over a three-year period.

We recognize compensation cost for our stock-based awards under the provisions of APB Opinion 25, which requires compensation cost to be measured by the quoted stock market price at the measurement date less the amount, if any, an employee is required to pay.

The required fair value method disclosures related to our stock-based compensation are as follows:

(in thousands, except per share amounts)	1997
Net income	
Actual	$ 144,642
Pro forma	$ 144,572
Earnings per share	
Actual	$ 2.71
Pro forma	$ 2.71

Stock option activity of the Plan was as follows:

Options outstanding at January 1, 1997	0
Options granted	298,400
Options forfeited	(25,400)
Options outstanding at December 31, 1997	273,000

Summarized information regarding stock options outstanding at December 31, 1997:

Range of Exercise Prices	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price
$25.75-$26.00	9.44	$25.84

No stock options were exercisable at December 31, 1997.

The stock options were granted with a weighted average grant date fair value of $2.22. The fair value was estimated using the Black-Scholes option pricing model with the following weighted average assumptions:

Expected life (years)	4.0
Risk-free interest rate	6.44%
Volatility	16%
Dividends	7.28%

Compensation cost recognized in income for our stock-based compensation awards in 1997 was $275,000.

Note I. Capital Stock

(dollars in thousands, except per share amounts)			December 31, 1997	1996
Common stock equity:				
Common stock, par value $1 per share, 100,000,000 shares authorized; 48,514,973 and 48,509,537 shares issued and outstanding:			$ 48,515	$ 48,510
Premium on common stock			696,137	695,723
Retained earnings			328,802	292,191
Total common stock equity			$ 1,073,454	$ 1,036,424

Dividends declared per share of common stock were $1.88 in 1997 and 1996 and $1.835 in 1995.

Cumulative preferred stock:

Par value $100 per share, 2,890,000 shares authorized; issued and outstanding:

Nonmandatory redeemable series:

Series	Current Shares Outstanding	Redemption Price/Share	1997	1996
4.25%	180,000	$103.625	$ 18,000	$ 18,000
4.78%	250,000	$102.800	25,000	25,000
7.75%	400,000	-	40,000	40,000
8.25%	-	-	0	40,000
			83,000	123,000
Less: redemption and issuance costs			0	(3,046)
Total nonmandatory redeemable series			$ 83,000	$ 119,954

Mandatory redeemable series:

Series	Current Shares Outstanding	Redemption Price/Share	1997	1996
7.27%	360,000	$102.420	$ 36,000	$ 40,000
8.00%	500,000	-	50,000	50,000
			86,000	90,000
Less: redemption and issuance costs			(5,907)	(6,535)
due within one year			(2,000)	(2,000)
Total mandatory redeemable series			$ 78,093	$ 81,465

1. Common Stock

Common stock issuances in 1995 through 1997 were as follows:

(in thousands)	Number of Shares	Total Par Value	Premium on Common Stock
Balance at December 31, 1994	45,535	$ 45,535	$ 622,803
Dividend reinvestment plan	468	468	11,404
New issuances	2,000	2,000	49,479
Balance at December 31, 1995	48,003	48,003	683,686
Dividend reinvestment plan	507	507	12,037
Balance at December 31, 1996	48,510	48,510	695,723
Dividend reinvestment plan	5	5	414
Balance at December 31, 1997	48,515	$ 48,515	$ 696,137

2. Cumulative Mandatory Redeemable Preferred Stock

The 360,000 shares of 7.27% sinking fund series cumulative preferred stock are currently redeemable at our option at $102.420. The redemption price declines annually each May to par value in May 2002. The stock is subject to a mandatory sinking fund requirement of 20,000 shares each May at par plus accrued dividends. We also have the noncumulative option each May to redeem additional shares, not to exceed 20,000, through the sinking fund at $100 per share plus accrued dividends. We redeemed, at par value, 40,000 shares in 1997 and 1996 and 20,000 shares in 1995.

We are not able to redeem any part of the 500,000 shares of 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.

Note J. Indebtedness

(in thousands)	December 31, 1997	1996
Long-term debt:		
Debentures:		
5.700%, due March 1997	$ 0	$ 100,000
5.950%, due March 1998	100,000	100,000
6.800%, due February 2000	65,000	65,000
6.050%, due August 2000	100,000	100,000
6.800%, due March 2003	150,000	150,000
7.800%, due May 2010	125,000	125,000
9.875%, due June 2020	100,000	100,000
9.375%, due August 2021	115,000	115,000
8.250%, due September 2022	60,000	60,000
7.800%, due March 2023	200,000	200,000
Total debentures	1,015,000	1,115,000
Less: due within one year	(100,000)	(100,000)
Net long-term debentures	915,000	1,015,000
Sewage facility revenue bonds	32,500	34,100
Less: due within one year	(667)	(667)
Less: funds held by trustee	(4,757)	(4,789)
Net long-term sewage facility revenue bonds	27,076	28,644
Massachusetts Industrial Finance Agency bonds:		
5.750%, due February 2014	15,000	15,000
6.662% bank loan, due 1999	100,000	0
Total long-term debt	$ 1,057,076	$ 1,058,644
Short-term debt:		
Notes payable:		
Bank loans	$ 94,013	$ 129,631
Commercial paper	43,000	71,823
Total notes payable	$ 137,013	$ 201,454

1. Long-term Debt

The 9 7/8% debentures due 2020 are first redeemable in June 2000 at a redemption price of 104.483%, the 9 3/8% series due 2021 are first redeemable in August 2001 at 104.612%, the 8.25% series due 2022 are first redeemable in September 2002 at 103.780% and the 7.80% series due 2023 are first redeemable in March 2003 at 103.730%. No other series are redeemable prior to maturity. There is no sinking fund requirement for any series of our debentures.

Sewage facility revenue bonds were issued by HEEC. The bonds are tax-exempt, subject to annual mandatory sinking fund redemption requirements and mature through 2015. In both May 1996 and 1997, we redeemed $1.6 million as scheduled. The weighted average interest rate of the bonds is 7.3%. A portion of the proceeds from the bonds is in reserve with the trustee. If HEEC should have insufficient funds to pay for extraordinary expenses, we would be required to make additional capital contributions or loans to the subsidiary up to a maximum of $1 million.

The 5.75% tax-exempt unsecured bonds due 2014 are redeemable beginning in February 2004 at a redemption price of 102%. The redemption price decreases to 101% in February 2005 and to par in February 2006.

In March 1997, we obtained $100 million of 6.662% notes in the form of a bank loan. This note matures in 1999.

The aggregate principal amounts of our long-term debt (including HEEC sinking fund requirements) due through 2002 are $101.6 million in 1998 and 1999, $166.6 million in 2000 and $1.6 million in 2001 and 2002.

2. 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 regulatory 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 utility short-term borrowings, comprised of bank loans and commercial paper, is as follows:

(dollars in thousands)	1997	1996	1995
Maximum short-term borrowings	$ 316,100	$ 272,500	$ 327,769
Weighted average amount outstanding	$ 212,663	$ 208,914	$ 165,720
Weighted average interest rates excluding commitment fees	5.85%	5.65%	6.21 %

In addition, at December 31, 1997, BETG had $7.5 million outstanding under a revolving credit agreement.

Note K. Fair Value of Financial Instruments

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 trust:
The cost of $151.6 million approximates fair value based on quoted market prices of securities held.

Cash and cash equivalents:
The carrying amount of $4.1 million approximates fair value due to the short-term nature of these securities.

Mandatory redeemable cumulative preferred stock, sewage facility revenue bonds and unsecured debt:
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, 1997, are as follows:

(in thousands)	Carrying Amount	Fair Value
Mandatory redeemable cumulative preferred stock	$ 80,093	$ 91,720
Sewage facility revenue bonds	$ 32,500	$ 35,084
Unsecured debt	$ 1,030,000	$ 1,073,982

Note L. Commitments and Contingencies

1. Contractual Commitments

At December 31, 1997, we had estimated contractual obligations for plant and equipment of approximately $18 million.

We have leases for certain facilities and equipment. Our estimated minimum rental commitments under both transmission agreements and noncancellable leases for the years after 1997 are as follows:

(in thousands)	
1998	$ 21,938
1999	18,958
2000	16,738
2001	12,356
2002	11,194
Years thereafter	91,874
Total	$ 173,058

Amounts above include $2.7 million which is expected to be assumed by Sithe Energies as part of our pending fossil divestiture discussed in Note C to these Consolidated Financial Statements.

The total of future minimum rental income to be received under noncancellable subleases related to the above leases is $300,921.

We will capitalize a portion of these lease rentals as part of plant expenditures in the future. The total expense for both lease rentals and transmission agreements was $27.5 million in 1997, $26.3 million in 1996 and $24.5 million in 1995, net of capitalized expenses of $1.2 million in 1997, $2.9 million in 1996 and $2.7 million in 1995.

We previously entered into various take or pay and throughput agreements, primarily to supply our New Boston fossil generating station with natural gas. The fixed and determinable portions of the obligations associated with these agreements are $19.5 million in 1998 and 1999 and $14.6 million in 2000. As part of our fossil divestiture agreement, Sithe Energies has agreed to assume these obligations. The total expense under these agreements was $47.1 million in 1997, $49.5 million in 1996 and $13.9 million in 1995.

2. Electric Company Investments

We have an approximately 11% equity investment in two companies which own and operate transmission facilities to import electricity from the Hydro-Quebec system in Canada. 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. At December 31, 1997, our portion of these guarantees was $16.6 million.

We have a 9.5% equity investment of approximately $2 million in Yankee Atomic Electric Company (Yankee Atomic). In 1992 the board of directors of Yankee Atomic decided to discontinue operations of the Yankee Atomic nuclear generating station permanently and decommission the facility.

Yankee Atomic received approval from the FERC to continue to collect its investment and decommissioning costs through 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 $13 million as of December 31, 1997. This estimate is recorded on our consolidated balance sheet as a power contract liability and an offsetting regulatory asset.

We also have a 9.5% equity investment in Connecticut Yankee Atomic Power Company (CYAPC) of approximately $11 million. In December 1996, the board of directors of CYAPC, which owns and operates the Connecticut Yankee nuclear electric generating unit (Connecticut Yankee), unanimously voted to retire the unit. The decision was based on an economic analysis of the costs of operating the unit through 2007, the period of its operating license, compared to the costs of closing the unit and incurring replacement power costs for the same period.

The current estimate of the sum of future payments for the closing, decommissioning and recovery of the remaining investment in Connecticut Yankee is approximately $615 million. Our share of these remaining estimated costs is $58 million. This estimate is recorded on our consolidated balance sheet as a power contract liability and an offsetting regulatory asset similar to Yankee Atomic.

In early 1997, CYAPC filed a rate case at the FERC seeking to recover certain post-operating costs, including decommissioning. The Connecticut Department of Public Utility Control (DPUC) has raised concerns to the FERC regarding CYAPC's estimate of these costs and the plant operator's prudency prior to the shutdown decision. The FERC set CYAPC's request for hearing before an Administrative Law Judge. The DPUC subsequently filed testimony in the proceeding asserting the position that the FERC should deny recovery of substantial post-operating costs, including a significant amount related to decommissioning and the return on CYAPC's undepreciated investment. We are currently unable to determine the ultimate outcome of this proceeding or its impact.

3. Nuclear Insurance

The federal Price-Anderson Act currently provides $8.9 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 $8.7 billion is provided by a retrospective assessment of up to $79.3 million per incident levied on each of the 110 nuclear generating units currently licensed to operate in the United States, with a maximum assessment of $10 million per reactor per accident in any year.

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 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 $10.4 million under both the replacement power and excess property damage, decontamination and decommissioning policies.

4. Hazardous Waste

We are an owner or operator of approximately 30 properties where oil or hazardous materials were spilled or released. As such, we are required to clean up these properties in accordance with a timetable developed by the Massachusetts Department of Environmental Protection. We continue to evaluate the costs associated with site cleanup. There are uncertainties associated with these costs due to the complexities of cleanup technology, regulatory requirements and he particular characteristics of the different sites. We also continue to face possible liability as a potentially responsible party in the cleanup of six multi-party hazardous waste sites in Massachusetts and other states where we are alleged to have generated, transported or disposed of hazardous waste at the sites. We are one of many potentially responsible parties and currently expect to have only a small percentage of the potential liability. Through December 31, 1997, we have accrued approximately $7 million related to our cleanup liabilities. We are unable to fully determine a range of reasonably possible cleanup costs in excess of the accrued amount, although based on our assessments of the specific site circumstances, we do not believe that it is probable that any such additional costs will have a material impact on our financial condition. However, it is reasonably possible that additional provisions for cleanup costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

5. Generating Unit Performance Program

Our recovery of the incremental purchased power costs resulting from outages at our generating units occurring through the retail access date is subject to review by the DTE. We are unable to fully determine a range of reasonably possible disallowance costs in excess of amounts accrued, although, based on the information currently available, we do not believe that it is probable that any such additional costs will have a material impact on our financial condition. However, it is reasonably possible that additional disallowance costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

6. Litigation

In October 1997, the DTE opened a proceeding to investigate our compliance with the 1993 order which permitted the formation of BETG and authorized us to invest up to $45 million in unregulated activities. We are unable to determine the ultimate outcome of this proceeding or its impact on our operations.

In the normal course of our business we are involved in certain other legal matters. We are unable to fully determine a range of reasonably possible litigation costs in excess of amounts accrued, although, based on the information currently available, we do not believe that it is probable that any such additional costs will have a material impact on our financial condition. However, it is reasonably possible that additional litigation costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

7. Industry Restructuring Legal Proceedings/Referendum Campaign

The DTE order approving our settlement agreement has been appealed by certain parties to the Massachusetts Supreme Judicial Court. In addition, along with other Massachusetts investor owned utilities, we have been named as a defendant in a class action suit seeking to declare certain provisions of the Massachusetts electric industry restructuring legislation unconstitutional. We are currently unable to determine the outcome of these proceedings or their impact on us.

Opponents of the electric industry restructuring legislation that was enacted in November 1997 have mounted a referendum campaign to repeal that law. A coalition of business, industry and public interest groups that supported the legislation, along with the electric utility industry, is opposed to the referendum and is prepared to mount an aggressive campaign to defeat it. We are currently unable to predict the eventual outcome of this referendum or its impact on us.

Note M. 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 a 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 on our consolidated income statements. Information relating to these contracts as of December 31, 1997, is as follows:

				proportionate share (in thousands)		
		Units of Capacity Purchased(a)				
Generating Unit	Contract Expiration Date	%	MW	Minimum Debt Service	Debt Outstanding Through Cont. Exp. Date	Annual Cost
Canal Unit 1	2002	25.0	141	$ 1,475	$ 5,172	$ 997
Mass. Bay Transportation Authority - 1	2005	100.0	34	-	-	2,166
Ocean State Power - Unit 1	2010	23.5	72	4,256	17,962	21,778
Ocean State Power - Unit 2	2011	23.5	72	3,592	15,951	23,969
Northeast Energy Associates	(b)	(b)	219	-	-	134,023
L'Energia (c)	2013	73.0	63	-	-	21,902
MassPower	2013	44.3	117	11,227	70,660	54,215
Mass. Bay Transportation Authority - 2	2019	100.0	34	-	-	577
Total			752	$ 20,550	$109,745	$ 287,627

(a) The Northeast Energy Associates contract represents 6.5% of our total system generation capability. The remaining units listed above represent approximately 16% in total.

(b) We purchase 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.

(c) We pay for this energy based on a price per kWh actually received.

Our total fixed and variable costs associated with these contracts in 1997, 1996 and 1995 were approximately $288 million, $281 million and $262 million, respectively. Our minimum fixed payments under these contracts for the years after 1997 are as follows:

(in thousands)	
1998	$ 88,406
1999	88,501
2000	89,853
2001	90,365
2002	92,768
Years thereafter	959,981
Total	$ 1,409,874
Total present value	$ 783,975

Under our settlement agreement, by July 1998 we are required to file a plan with the DTE describing the actions we intend to take to sell, assign or otherwise dispose of our purchased power contracts.

2. Long-Term Power Sales Contracts

In addition to other wholesale power sales, we sell a percentage of Pilgrim Station's output to other utilities and municipalities 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 and municipalities pay their proportionate 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 investment.

Report of Independent Accountants

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, 1997 and 1996, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1997. 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, 1997 and 1996, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1997, in conformity with generally accepted accounting principles.

Boston, Massachusetts
January 22, 1998

Selected Consolidated Quarterly Financial Data (Unaudited)

(in thousands, except earnings per share)

	Operating Revenues	Operating Income	Net Income	Earnings Available for Common Shareholders	Earnings Per Average Common Share (a)
1997					
First quarter	$ 422,725	$ 47,589	$ 20,935	$ 17,118	$ 0.35
Second quarter	426,735	60,487	33,978	30,484	0.63
Third quarter	519,513	108,060	81,418	78,499	1.62
Fourth quarter	407,260	44,714	8,311	5,392	0.11
1996					
First quarter	$ 387,849	$ 52,093	$ 25,203	$ 21,313	$ 0.44
Second quarter	389,756	55,232	27,926	24,086	0.50
Third quarter	497,968	105,353	80,011	76,194	1.58
Fourth quarter	390,730	35,252	8,406	4,588	0.09

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

Selected Quarterly Common Stock Data (Unaudited)

The reported high and low market value per share of our common stock as reported in the *Wall Street Journal* and the dividends declared per share for each of the quarters in 1997 and 1996 was as follows:

	1997			1996		
	High	Low	Dividends	High	Low	Dividends
First quarter	$27 3/8	$ 26	$0.470	$30 1/8	$26 1/4	$0.470
Second quarter	26 5/8	24 5/8	0.470	27 1/8	23 5/8	0.470
Third quarter	30 7/8	26 1/2	0.470	25 3/8	21 3/4	0.470
Fourth quarter	38 3/8	30 1/4	0.470	27	21 3/4	0.470

Selected Consolidated Operating Statistics (Unaudited)

	1997	1996	1995	1994	1993
Capacity - MW:					
Pilgrim Station	670	670	669	669	670
New Boston Station	760	730	760	760	760
Mystic Station	994	994	1,005	1,006	1,006
W.F. Wyman Unit 4	37	37	36	36	36
Jet turbines	276	278	284	287	283
Total (a)	2,737	2,709	2,754	2,758	2,755
Contract purchases	941	1,237	1,274	1,035	938
Contract sales	(281)	(333)	(340)	(373)	(283)
Net capability at year-end	3,397	3,613	3,688	3,420	3,410
Net capability at peak - MW	3,444	3,385	3,466	3,484	3,663
Capability responsibility to NEPOOL at peak - MW	3,312	3,256	3,306	3,306	3,190
Company territory:					
Hourly peak - MW	2,835	2,703	2,785	2,798	2,662
Load factor	61.0 %	63.4 %	60.0 %	58.9 %	60.5 %
Capability (net kW):					
Fossil	85 %	86 %	85 %	84 %	84 %
Nuclear	15 %	14 %	15 %	16 %	16 %
Generation (system kWh excluding interchange):					
Fossil	80 %	69 %	73 %	75 %	68 %
Nuclear	20 %	31 %	27 %	25 %	32 %
Utility plant ($ in 000's):					
Expenditures	$ 114,110	$ 145,347	$ 180,822	$ 198,771	$ 246,774
Retirements	21,449	68,688	48,111	45,673	34,147
Accumulated depreciation	1,713,079	1,550,317	1,439,996	1,344,452	1,258,359
Depreciable plant	4,375,391	4,317,028	4,235,347	3,994,212	3,841,752
Number of utility employees at year-end	3,227	3,362	3,812	4,026	4,397

(a) Based upon winter capability audit results.

Selected Consolidated Sales Statistics (Unaudited)

	1997	1996	1995	1994	1993
Electric energy (kWh in thousands):					
Sources (system output):					
Generated	11,686,810	10,531,745	10,537,114	9,428,931	9,787,092
Purchased	6,014,208	5,680,194	5,446,542	5,920,065	5,326,224
New England Power Pool	887,250	1,842,732	1,513,467	1,535,335	1,575,310
Total	18,588,268	18,054,671	17,497,123	16,884,331	16,688,626
Disposition:					
Commercial	7,991,349	7,821,371	7,454,684	7,478,631	7,263,358
Residential	3,566,405	3,549,899	3,563,626	3,534,372	3,477,870
Industrial	1,467,600	1,547,630	1,538,218	1,539,385	1,580,969
Other (a)	131,187	130,678	131,626	130,721	145,242
Total retail sales	13,156,541	13,049,578	12,688,154	12,683,109	12,467,439
Wholesale and contract sales (a)	2,674,283	3,127,087	2,805,777	2,367,589	2,272,669
New England Power Pool	1,610,860	741,390	884,336	725,439	877,978
Total system	17,441,684	16,918,055	16,378,267	15,776,137	15,618,086
Miscellaneous usage	1,146,584	1,136,616	1,118,856	1,108,194	1,070,540
Total	18,588,268	18,054,671	17,497,123	16,884,331	16,688,626
Kilowatthour sales - annual growth:					
Commercial	2.2 %	4.9 %	(0.3) %	3.0 %	1.2 %
Residential	0.5	(0.4)	0.8	1.6	1.9
Industrial	(5.2)	0.6	(0.1)	(2.6)	(5.4)
Other	0.4	(0.7)	0.7	(10.0)	(50.3)
Total retail sales (a)	0.8	2.8	-	1.7	(0.7)
Wholesale and contract sales	(14.5)	11.5	18.5	4.2	(9.7)
New England Power Pool	117.3	(16.2)	21.9	(17.4)	(53.7)
Total system	3.1 %	3.3 %	3.8 %	1.0 %	(8.0) %
Electric operating revenues by class:					
Commercial	51 %	50 %	50 %	50 %	49 %
Residential	27 %	27 %	28 %	28 %	28 %
Industrial	9 %	9 %	9 %	9 %	10 %
Other	1 %	2 %	2 %	2 %	1 %
Wholesale and contract	12 %	12 %	11 %	11 %	12 %
Average number of customers	662,354	657,487	653,757	655,707	651,141

(a) Effective in both November 1995 and February 1993, a former retail customer became a wholesale customer as allowed under Massachusetts state law.

Officers

Thomas J. May, Chairman of the Board, President and Chief Executive Officer

Ronald A. Ledgett, Executive Vice President

Alison Alden, Senior Vice President - Sales, Services and Human Resources

L. Carl Gustin, Senior Vice President - Corporate Relations

Douglas S. Horan, Senior Vice President - Strategy and Law and General Counsel

James J. Judge, Senior Vice President - Corporate Services and Treasurer

William N. Dimoulas, Vice President - Information Technology

Philippe A. Frangules, Vice President - Strategic Planning and Business Development

Richard S. Hahn, Vice President - Technology

Leon J. Olivier, Vice President - Nuclear Operations and Station Director

David M. Samuel, Vice President - Customer Care

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

Theodora S. Convisser, Clerk of the Corporation

Donald Anastasia, Assistant Treasurer

Directors

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

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

d,e Richard J. Egan, Chairman of the Board, EMC Corporation (storage-related computer system products)

b,c,d Charles K. Gifford, Chairman and Chief Executive Officer, BankBoston Corporation (bank holding company) and BankBoston, N.A.

a,b Nelson S. Gifford, Principal, Fleetwing Capital (venture investments)

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

a,c Thomas J. May, Chairman of the Board, President and Chief Executive Officer, Boston Edison Company

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

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

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

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

Selected Consolidated Financial Statistics (Unaudited)

	1997	1996	1995	1994	1993
Operating revenues (000)	$ 1,776,233	$ 1,666,303	$ 1,628,503	$ 1,544,735	$ 1,482,159
Earnings available for common (000)	$ 131,493	$ 126,181	$ 96,739 (a)	$ 109,257	$ 102,513
Per common share:					
Earnings	$ 2.71	$ 2.61	$ 2.08 (a)	$ 2.41	$ 2.28
Dividends declared	$ 1.880	$ 1.880	$ 1.835	$ 1.775	$ 1.715
Dividends paid	$ 1.88	$ 1.88	$ 1.82	$ 1.76	$ 1.70
Book value	$ 22.13	$ 21.37	$ 20.61	$ 20.11	$ 19.42
Payout ratio	69 %	72 %	88 %(a)	73 %	75 %
Return on average common equity	12.4 %	12.4 %	10.0 %(a)	12.1 %	11.9 %
Year-end dividend yield	5.0 %	7.0 %	6.4 %	7.6 %	5.9 %
Fixed charge coverage (SEC)	2.95	2.91	2.38	2.46	2.22
Capitalization:					
Total debt	51 %	52 %	54 %	56 %	57 %
Preferred equity	7 %	8 %	8 %	9 %	9 %
Common equity	42 %	40 %	38 %	35 %	34 %
Long-term debt (000)	$ 1,057,076	$ 1,058,644	$ 1,160,223	$ 1,136,617	$ 1,272,497
Mandatory redeemable preferred stock (000)	$ 80,093	$ 83,465	$ 86,837	$ 88,837	$ 90,837
Total assets (000)	$ 3,622,347	$ 3,729,291	$ 3,637,170	$ 3,608,699	$ 3,468,724
Internal generation after dividends (000)	$ 240,362	$ 257,446	$ 184,492	$ 217,030	$ 194,209
Plant expenditures (000)	$ 114,110	$ 145,347	$ 180,822	$ 198,771	$ 246,774
Internal generation	211 %	177 %	102 %	109 %	79 %
Common shares outstanding:					
Weighted average	48,514,958	48,264,734	46,591,662	45,337,661	44,959,050
Year-end	48,514,973	48,509,537	48,003,178	45,535,477	45,129,227
Stock price:					
High	38 3/8	30 1/8	29 1/2	29 7/8	32 5/8
Low	24 5/8	21 3/4	23 1/8	21 1/2	26 3/8
Year-end	37 7/8	26 7/8	29 1/2	24	29 3/4
Year-end market value (000)	$ 1,837,505	$ 1,303,694	$ 1,416,094	$ 1,092,851	$ 1,342,595
Trading volume (shares)	37,732,900	41,105,700	23,078,900	25,095,100	18,729,400
Market/book ratio (year-end)	1.71	1.26	1.43	1.19	1.53
Price/earnings ratio (year-end)	14.0	10.3	14.2 (a)	10.0	13.0

(a) Amounts excluding $34 million pre-tax restructuring charge:

Earnings available for common (000)	$ 117,403
Earnings	$ 2.52
Payout ratio	72 %
Return on average common equity	12.2 %
Price/earnings ratio	11.7 %

Certain reclassifications and recalculations were made to the data reported in prior years to conform with the method of presentation used in 1997.

Important Shareholder Information

Shareholder Inquiries

If you have questions concerning your dividend payments, the Dividend Reinvestment and Common Stock Purchase Plan, direct deposit service, transfer procedures or other stock account matters, please contact our stock transfer agent at the following address:

Boston EquiServe
Shareholder Services Division
P.O. Box 8040
Boston, MA 02266-8040
Toll Free Phone: 1-800-338-8446

Telecommunication Device for the Deaf (TDD)
1-800-952-9245.

Dividend Payment Dates

Common and Preferred
1st of February, May, August and November

Tax Status of 1997 Dividends

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

Stock Symbol and Exchange Listings

Ticker Symbol: BSE
New York (NYSE) and Boston stock exchanges

1998 Annual Shareholders Meeting

All shareholders are invited to attend our Annual Meeting on Tuesday, May 5, 1998, at 11:00 A.M. at the Boston Back Bay Hilton, Second Floor, Belvidere Ballroom, 40 Dalton Street, Boston, Massachusetts.

Dividend Payments - Direct Deposit Service

Shareholders receiving dividend checks can arrange for electronic direct deposit. Transfers are made on the dividend payment dates and confirmation statements are mailed to shareholders. To take advantage of this convenient program, contact our stock transfer agent as noted above.

Dividend Reinvestment and Common Stock Purchase Plan

Our Dividend Reinvestment and Common Stock Purchase Plan (the plan) is available to our common and preferred shareholders, our residential electric customers and employees. Participants do not pay brokerage fees or commissions related to the purchase of shares. Some important features of the plan are as follows:

- Optional cash payments invested monthly
- $50 per month minimum not to exceed $40,000 per calendar year
- Safekeeping of common stock certificates

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 record holder. If for any reason you are unable to arrange participation with your broker or bank nominee, you must become a record holder by having the shares transferred to your own name.

Automatic Monthly Investment Program

Shareholders who are participants in the Dividend Reinvestment and Common Stock Purchase Plan may now make automatic monthly investments of a specified amount (not less than $50 per month) through an Automated Clearing House ("ACH") withdrawal from their savings or checking account. Once automatic monthly deductions are initiated, funds will be drawn from your designated bank account on the 25th of each month and will be invested in common stock on the next investment date. For more information on the Automatic Monthly Investment Program, or an enrollment form, contact our stock transfer agent.

Safekeeping Program

Shareholders who are participants in the Dividend Reinvestment and Common Stock Purchase Plan can transfer their common stock certificates into their plan account for safekeeping. Dividends on those shares will be reinvested automatically like any other shares held in the plan. To continue receiving cash dividends, you must hold your shares in certificate form. For additional information, contact our stock transfer agent.

SEC Form 10-K

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

Quarterly Report to Shareholders

Beneficial owners of our stock whose shares are registered in names other than their own may obtain copies of our Quarterly Reports to Shareholders by contacting our Investor Relations Department. Note that the Annual Report will continue to be mailed to beneficial owners directly by their bank or broker.

Investor & Shareholder Contacts

Philip J. Lembo
Director, Investor Relations
(617) 424-3562
or
Jean M. Carella
Investor Relations Specialist
(617) 424-2658

Email Address

ir@bedison.com

Internet Address

www.bostonedison.com

Company Contact

Theodora S. Convisser
Clerk of the Corporation

General Offices

800 Boylston Street
Boston, MA 02199-8003
(617) 424-2000

Boston Edison

800 Boylston Street
Boston, Massachusetts 02199-8003