GREEN MOUNTAIN POWER CORP
Form 10-K
March 28, 2001

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

_X_ Annual Report Pursuant to Section 13 or 15(d)

of the Securities Exchange Act of 1934

___ Transition Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2000

COMMISSION FILE NUMBER 1-8291

GREEN MOUNTAIN POWER CORPORATION

(Exact name of registrant as specified in its charter)

Vermont	03-0127430
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

163 Acorn Lane
Colchester, VT 05446

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code (802) 864-5731

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

Title of Each Class	Name of each exchange on which registered
COMMON STOCK, PAR VALUE $3.33-1/3 PER SHARE	NEW YORK STOCK EXCHANGE

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

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

THE AGGREGATE MARKET VALUE OF THE VOTING STOCK HELD BY NON-AFFILIATES OF THE REGISTRANT AS OF MARCH 21, 2001, WAS APPROXIMATELY $77,278,643 BASED ON THE CLOSING PRICE OF $13.84 FOR THE COMMON STOCK ON THE NEW YORK STOCK EXCHANGE AS REPORTED BY THE WALL STREET JOURNAL.

THE NUMBER OF SHARES OF COMMON STOCK OUTSTANDING ON MARCH 21, 2001, WAS 5,583,717

DOCUMENTS INCORPORATED BY REFERENCE

The Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 17, 2001, to be filed with the Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, is incorporated by reference in Items 10, 11, 12 and 13 of Part III of this Form 10-K.

2

Green Mountain Power Corporation
Form 10-K for the fiscal year ended December 31, 2000
Table of contents

PART I

ITEM 1. BUSINESS

THE COMPANY

Green Mountain Power Corporation (the "Company") is a public utility operating company engaged in supplying electrical energy in the State of Vermont in a territory with approximately one quarter of the State's population. We serve approximately 86,000 customers. The Company was incorporated under the laws of the State of Vermont on April 7, 1893.

Our sources of revenue for the year ended December 31, 2000 were as follows:

* 25.2% from residential customers;
* 25.4% from small commercial and industrial customers;
* 16.0% from large commercial and industrial customers;
* 31.9% from sales to other utilities; and
* 1.5% from other sources.

During 2000, our energy resources for retail and wholesale sales of electricity were obtained as follows:

* 35.8% from hydroelectric sources (3.9% Company-owned, 0.1% New York Power Authority ("NYPA"), 29.5% Hydro-Quebec and 2.3% small power producers);
* 28.8% from a nuclear generating source (the Vermont Yankee nuclear plant described below);

* 2.8% from wood;
* 2.7% from oil;
* 2.2% from natural gas; and
* 0.4% from wind.

The remaining 27.3% was purchased on a short-term basis from other utilities through the Independent System Operator of New England ("ISO"), formerly the New England Power Pool ("NEPOOL").

In 2000, we purchased 92.8% of the energy required to satisfy our retail and wholesale sales of electricity (including energy purchased from Vermont Yankee Nuclear Power Corporation ("Vermont Yankee") and under other long-term purchase arrangements). See Note K of Notes to Consolidated Financial Statements("Notes"), Annual Report to Stockholders, 2000 ("Annual Report").

A major source of the Company's power supply is our entitlement to a share of the power generated by the 531 megawatt (MW) Vermont Yankee nuclear generating plant owned and operated by Vermont Yankee Nuclear Power Corporation. We have a 17.9% equity interest in Vermont Yankee. For information concerning Vermont Yankee, see Power Resources - Vermont Yankee.

The Company participates in NEPOOL, a regional bulk power transmission organization established to assure reliable and economical power supply in the Northeast. The ISO was created to manage the operations of NEPOOL in 1999. The ISO works as a clearinghouse for purchasers and sellers of electricity in the new deregulated markets. Sellers place bids for the sale of their generation or purchased power resources and if demand is high enough the output from those resources is sold. We must purchase additional electricity to meet customer demand during periods of high usage and to replace energy repurchased by Hydro-Quebec under an arrangement negotiated in 1997. Our costs to serve demand during periods of warmer than normal temperatures in summer months and to replace such energy repurchases by Hydro-Quebec rose substantially after the market opened to competitive bidding on May 1, 1999. The cost of securing future power supplies has also risen in tandem with higher summer supply costs.

The Company's principal service territory is an area roughly 25 miles in width extending 90 miles across north central Vermont between Lake Champlain on the west and the Connecticut River on the east. Included in this territory are the cities of Montpelier, Barre, South Burlington, Vergennes and Winooski, as well as the Village of Essex Junction and a number of smaller towns and communities. We also distribute electricity in four separate areas located in southern and southeastern Vermont that are interconnected with our principal service area through the transmission lines of Vermont Electric Power Company, Inc. ("VELCO") and others. Included in these areas are the communities of Vernon (where the Vermont Yankee plant is located), Bellows Falls, White River Junction, Wilder, Wilmington and Dover. We supply at wholesale a portion of the power requirements of several municipalities and cooperatives in Vermont. We are obligated to meet the changing electrical requirements of these wholesale customers, in contrast to our obligation to other wholesale customers, which is limited to specified amounts of capacity and energy established by contract.

Major business activities in our service areas include computer assembly and components manufacturing (and other electronics manufacturing), software development, granite fabrication, service enterprises such as government, insurance, regional retail shopping and tourism (particularly winter recreation), and dairy and general farming.

SEGMENT INFORMATION

The Company has partially sold or disposed of the operations and assets of Mountain Energy, Inc. ("MEI"), classified as discontinued operations in 1999. MEI was renamed Northern Water Resources, Inc. in January 2001. Industry segment information required to be disclosed is presented in Note L of the Notes to Annual Report.

SEASONAL NATURE OF BUSINESS

Winter recreational activities, longer hours of darkness and heating loads from cold weather usually cause our peak electric sales to occur in December, January or February. Our heaviest load in 2000, 323.5 MW, occurred on January

17, 2000.

We charge our customers higher rates for billing cycles in December through March and lower rates for the remaining months. These are called seasonally differentiated rates. In order to eliminate the impact of the seasonally differentiated rates on earnings, we defer some of the revenues from those four months and account for them in later periods in which we have lower revenues or higher costs. In prior periods, by deferring certain revenues we are able to match our revenues to our costs more accurately.

Under this structure, retail electric rates produce average revenues per kilowatt-hour during four peak season months (December through March) that are approximately 30% higher than during the eight off-season months (April through November). See Energy Efficiency and Rate Design.

Under NEPOOL market rules implemented in May 1999, the cost basis that had supported the Company's rate design was eliminated, making the seasonal rate structure no longer appropriate. A request to eliminate the seasonal rate structure in all classes of service effective April 2001 was approved by the Vermont Public Service Board (the "VPSB") in January 2001.

SINGLE CUSTOMER DEPENDENCE

The Company had one major retail customer, IBM, metered at two locations, that accounted for 11.2 percent, 11.8 percent, and 14.7 percent of total operating revenues, and 16.5 percent, 16.4 percent and 17.1 percent of the Company's retail operating revenues in 2000, 1999 and 1998, respectively. IBM's percent of total revenues in 2000 decreased due to an increase in total operating revenues as a result of sales for resale pursuant to the Company's power supply agreement with Morgan Stanley Capital Group, Inc. ("MS"), which is discussed in greater detail in Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD and A")-Power Contract Commitments. No other retail customer accounted for more than 1.0% of our revenue during the past three years. Under the present regulatory system, the loss of IBM as a customer would require the Company to seek rate relief to recover the revenues previously paid by IBM from other customers in an amount sufficient to offset the fixed costs that IBM had been covering through its payments. See Notes A and K of the Notes to Annual Report.

Operating statistics for the past five years are presented in the following table.

GREEN MOUNTAIN POWER CORPORATION

Operating Statistics	For the years ended December 31,			
	2000	1999	1998	1997
Total capability (MW)	411.1	393.2	396.9	41
Net system peak	323.5	317.9	312.5	31
Reserve (MW)	87.6	75.3	84.4	10
Reserve % of peak	27.1%	23.7%	27.0%	3
Net Production (MWH**)				
Hydro	1,053,223	1,095,738	972,723	1,073,
Wind	12,246	7,956	-	
Nuclear	803,303	731,431	607,708	772,
Conventional steam	2,704,427	2,328,267	750,602	560,
Internal combustion	35,699	12,312	40,148	4,
Combined cycle	73,433	99,962	118,322	104,
Total production	4,682,331	4,275,666	2,489,503	2,515,

Less non-firm sales to other utilities.	2,573,576	2,152,781	499,409	524,
Production for firm sales	2,108,755	2,122,885	1,990,094	1,991,
Less firm sales and lease transmissions.	1,954,898	1,920,257	1,883,959	1,870,
Losses and company use (MWH).	153,857	202,628	106,134	120,
Losses as a % of total production	3.29%	4.74%	4.26%	4
System load factor (***).	68.8%	80.3%	71.8%	7
Net Production (% of Total)				
Hydro	22.5%	25.6%	39.1%	4
Wind.	0.3%	0.2%	0.0%	
Nuclear	17.1%	17.1%	24.4%	3
Conventional steam.	57.8%	54.5%	30.2%	2
Internal combustion	0.8%	0.3%	1.6%	
Combined cycle.	1.6%	2.3%	4.8%	
Total	100.0%	100.0%	100.0%	10
Sales and Lease Transmissions(MWH)				
Residential - GMPC.	558,682	544,447	533,904	549,
Commercial & industrial - small	704,126	688,493	665,707	645,
Commercial & industrial - large	683,296	664,110	636,436	608,
Other	6,713	3,138	3,476	3,
Total retail sales and lease transmissions. . . .	1,952,817	1,900,188	1,839,522	1,806,
Sales to Municipals & Cooperatives (Rate W) . . .	2,081	20,069	44,437	64,
Total Requirements Sales.	1,954,898	1,920,257	1,883,959	1,870,
Other Sales for Resale.	2,573,576	2,152,781	499,409	524,
Total sales and lease transmissions(MWH)	4,528,474	4,073,038	2,383,368	2,395,
Average Number of Electric Customers				
Residential	72,424	71,515	71,301	70,
Commercial and industrial small	12,746	12,438	12,170	11,
Commercial and industrial large	23	23	23	
Other	65	66	70	
Total.	85,258	84,042	83,564	82,
Average Revenue Per KWH (Cents)				
Residential including lease revenues.	12.50	12.32	11.56	11
Commercial & industrial - small	10.00	9.88	9.29	9
Commercial & industrial - large	6.51	6.55	6.32	6
Total retail including lease.	9.52	9.47	8.96	8
Average Use and Revenue Per Residential Customer				
KWh's including lease transmissions	7,717	7,617	7,488	7,
Revenues including lease revenues	$ 965	$ 938	$ 865	$

(*) MW - Megawatt is one thousand kilowatts.
(**) MWH - Megawatt hour is one thousand kilowatt hours.
(***) Load factor is based on net system peak and firm MWH production less off-system losses.

EMPLOYEES

As of December 31, 2000, the Company had 197 employees, exclusive of temporary employees, and our subsidiary, MEI, had five employees. The 101 union employees on strike from January 4, 2001 through January 26, 2001 acted professionally throughout the three week strike. The Company considers its relations with employees to be excellent.

STATE AND FEDERAL REGULATION

General. The Company is subject to the regulatory authority of the VPSB, which extends to retail rates, services and facilities, securities issues and various other matters. The separate Vermont Department of Public Service (the "Department"), created by statute in 1981, is responsible for development of energy supply plans for the State of Vermont (the "State"), purchases of power as an agent for the State and other general regulatory matters. The VPSB principally conducts quasi-judicial proceedings, such as rate setting. The Department, through a Director for Public Advocacy, is entitled to participate as a litigant in such proceedings and regularly does so.

Our rate tariffs are uniform throughout our service area. We have entered into a number of jobs incentive agreements, providing for reduced capacity charges to large customers applicable only to new load. We have an economic development agreement with IBM that provides for contractually established charges, rather than tariff rates, for incremental loads. See Item 7. MD and A - Results of Operations - Operating Revenues and MWh Sales.

Our wholesale rate on sales to two wholesale customers is regulated by the Federal Energy Regulatory Commission ("FERC"). Revenues from sales to these customers were less than 1% of operating revenues for 2000.

We provide transmission service to twelve customers within the State under rates regulated by the FERC; revenues for such services amounted to less than 1.0% of the Company's operating revenues for 2000.

On April 24, 1996, the FERC issued Orders 888 and 889 which, among other things, required the filing of open access transmission tariffs by electric utilities, and the functional separation by utilities of their transmission operations from power marketing operations. Order 888 also supports the full recovery of legitimate and verifiable wholesale power costs previously incurred under federal or state regulation.

On July 17, 1997, the FERC approved our Open Access Transmission Tariff, and on August 30, 1997 we filed our compliance refund report. In accordance with Order 889, we have also functionally separated our transmission operations and filed with the FERC a code of conduct for our transmission operations. We do not anticipate any material adverse effects or loss of wholesale customers due to the FERC orders mentioned above. The Open Access tariff could reduce the amount of capacity available to the Company from such facilities in the future. See Item 7. MD and A - Transmission Expenses.

The Company has equity interests in Vermont Yankee, VELCO and Vermont Electric Transmission Company, Inc. ("VETCO"), a wholly owned subsidiary of VELCO. We have filed an exemption statement under Section 3(a)(2) of the Public Utility Holding Company Act of 1935, thereby securing exemption from the provisions of such Act, except for Section 9(a)(2), which prohibits the acquisition of securities of certain other utility companies without approval of the Securities and Exchange Commission ("SEC"). The SEC has the power to institute proceedings to terminate such exemption for cause.

Licensing. Pursuant to the Federal Power Act, the FERC has granted licenses for the following hydro-electric projects owned by the Company:

	Issue Date	Licensed Period
Project Site:		
Bolton. . . .	February 5,1982	February 5,1982 - February 4, 2022
Essex	March 30, 1995	March 1, 1995 - March 1, 2025
Vergennes . .	June 29, 1999	June 1, 1999 - May 31, 2029
Waterbury . .	July 20, 1954	September 1, 1951 - August 31, 2001

Major project licenses provide that after an initial twenty-year period, a portion of the earnings of such project in excess of a specified rate of return is to be set aside in appropriated retained earnings in compliance with FERC Order #5, issued in 1978. Although the twenty-year periods expired in 1985, 1969 and 1971 in the cases of the Essex, Vergennes and Waterbury projects, respectively, the amounts appropriated are not material.

The relicensing application for Waterbury was filed in August 1999. The Company expects the project to be relicensed for a 30 year term in the near future and does not have any competition for the licenses.

Department of Public Service Twenty-Year Electric Plan. In December 1994, the Department adopted an update of its twenty-year electrical power-supply plan (the "Plan") for the State. The Plan includes an overview of statewide growth and development as they relate to future requirements for electrical energy; an assessment of available energy resources; and estimates of future electrical energy demand.

In June 1996, we filed with the VPSB and the Department an integrated resource plan pursuant to Vermont Statute 30 V.S.A. 218c. That filing is still pending before the VPSB.

RECENT RATE DEVELOPMENTS

On March 2, 1998, the VPSB released its Order dated February 27, 1998 in the then pending rate case. The VPSB authorized us to increase our rates by 3.61 percent, which gave us increased annual revenues of $5.6 million. The VPSB Order denied us the right to charge customers $5.48 million of the annual costs for power purchased under our contract with Hydro-Quebec. The VPSB denied recovery of these costs for the following reasons:

* the VPSB claimed that we had acted imprudently by committing to the power contract with Hydro-Quebec in August 1991 (the imprudence disallowance); and
* to the extent that the costs of power to be purchased from Hydro-Quebec were then higher than current estimates of market prices for power during the Contract term, after accounting for the imprudence disallowance, the contract power was not "used and useful".

On May 8, 1998, we filed a request with the VPSB to increase our retail rates by 12.93 percent due to higher power costs, the cost of the January 1998 ice storm, and investments in new plant and equipment.

On November 18, 1998, by Memorandum of Understanding ("MOU"), the Company, the Department and IBM agreed to stay rate proceedings in the 1998 rate case until or after September 1, 1999, or such earlier date as the parties may later agree to or the VPSB may order. The agreement to suspend our 1998 rate case delayed the date of a final decision on the 1998 rate case to December 15, 1999, and we recognized an additional loss of $5.25 million in the last quarter of 1998 representing the effect of the continued disallowance of Hydro-Quebec costs through December 15, 1999. The MOU provided for a 5.5% temporary retail rate increase, to produce $8.9 million in annualized additional revenue, effective with service rendered December 15, 1998. An additional surcharge was permitted, without further VPSB order, in order to produce additional revenues necessary to provide the Company with the capacity to finance 1999 Pine Street Barge Canal site expenditures. The MOU was approved by the VPSB on December 11, 1998. The MOU did not provide for any specific disallowance of power costs under our purchase power contract with Hydro-Quebec. Issues respecting recovery of such power costs were preserved for future proceedings. The stay and suspension of this pending rate case and the temporary rate levels agreed to in the MOU were designed to allow us to continue to provide adequate and efficient service to our customers while we seek mitigation of power supply costs.

On September 7 and December 17, 1999, the VPSB issued Orders approving two amendments to the MOU that the Company had entered into with the Department and IBM. The two amendments continued the stay of proceedings until September 1, 2000, with a final decision expected by December 31, 2000. The amendments maintained the other features of the original MOU, and the second amendment provided for a temporary rate increase of 3 percent, in addition to the current temporary rate level, to become effective as of January 1, 2000.

The Company reached a final settlement agreement with the Department in the pending rate case during November 2000. The final settlement agreement contains the following provisions:

* A rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases become permanent;
* Rates are set at levels that recover the Company's Hydro-Quebec VJO contract costs, effectively ending the regulatory disallowances experienced by the Company over the past three years;
* The Company agrees not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;
* The Company agreed to write off approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaces short-term credit facilities with long-term debt or equity financing;
* Seasonal rates will be eliminated April 2001, which is expected to generate approximately $6 million in cash flow that can be utilized to offset increased costs during 2001, 2002 and 2003; and
* The Company agrees to consult extensively with the Department regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions:

* The VPSB Order requires the Company and customers to share equally, with an $8.0 million limit to the customers' share, any premium above book value realized by the Company in any future merger, acquisition or asset sale; and
* The second condition restricts Company investments in non-utility operations.

For further information regarding recent rate developments, see Item 7. MD and A - Liquidity and Capital Resources, Rates, and Note I of Notes to Annual Report.

COMPETITION AND RESTRUCTURING

Electric utilities historically have had exclusive franchises for the retail sale of electricity in specified service territories. Legislative authority has existed since 1941 that would permit Vermont cities, towns and villages to own and operate public utilities. Since that time, no municipality served by the Company has established or, as far as is known to the Company, is presently taking steps to establish a municipal public utility.

In 1987, the Vermont General Assembly enacted legislation that authorized the Department to sell electricity on a significantly expanded basis. Before the new law was passed, the Department's authority to make retail sales had been limited. It could sell at retail only to residential and farm customers and could sell only power that it had purchased from the Niagara and St. Lawrence projects operated by the New York Power Authority.

Under the law, the Department can sell electricity purchased from any source at retail to all customer classes throughout the State, but only if it convinces the VPSB and other State officials that the public good will be served by such sales. The Department has made limited additional retail sales of electricity. The Department retains its traditional responsibilities of public advocacy before the VPSB and electricity planning on a statewide basis.

In certain states across the country, including the New England states, legislation has been enacted to allow retail customers to choose their electricity suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems. Increased competitive pressure in the electric utility industry may restrict the Company's ability to charge energy prices sufficient to recover embedded costs, such as the cost of purchased power obligations or of generation facilities owned by the Company. The amount by which such costs might exceed market prices is commonly referred to as stranded costs.

Regulatory and legislative authorities at the federal level and in some states, including Vermont where legislation has not been enacted, are considering how to facilitate competition for electricity sales. For further information regarding Competition and Restructuring, See Item 7. MD and A - Future Outlook.

POWER RESOURCES

The Company has renewed a contract with Morgan Stanley Capital Group, Inc. as the result of our all power requirements solicitation in 1999. See Notes I and K of Notes to Consolidated Financial Statements.

The Company generated, purchased or transmitted 2,790,018 MWh of energy for retail and requirements wholesale customers for the twelve months ended December 31, 2000. The corresponding maximum one-hour integrated demand during that period was 323.5 MW on January 17, 2000. This compares to the previous all-time peak of 322.6 MW on December 27, 1989. The following table shows the net generated and purchased energy, the source of such energy for the twelve-month period and the capacity in the month of the period system peak. See Note K of Notes to Annual Report.

Net Electricity Generated and Purchased and Capacity at Peak

	During year Ended 12/31/2000 MWH	percent	At time of annual peak KW	percent
Wholly-owned plants:				
Hydro	108,230	3.9%	35,300	8.6%
Diesel and Gas Turbine.	35,699	1.3%	46,200	11.3%
Wind.	12,246	0.4%	850	0.2%
Jointly-owned plants:				
Wyman #4.	15,443	0.6%	7,100	1.7%
Stony Brook I	50,537	1.8%	31,000	7.6%
McNeil.	33,569	1.2%	6,600	1.6%
Owned in association with Others:				
Vermont Yankee Nuclear.	803,303	28.8%	95,680	23.3%
Long Term Purchases:				
Hydro-Quebec.	824,993	29.5%	114,200	27.8%
Stony Brook I	22,896	0.8%	14,150	3.5%
Other:				
NYPA.	1,453	0.1%	250	0.1%
Small Power Producers	120,000	4.3%	24,650	6.0%
Short-term purchases.	761,649	27.3%	34,100	8.3%
Total	2,790,018		410,080	
Less system sales energy.	(2,256)		-	

Net Own Load.	2,787,762	100.00%	410,080	100.00%

Vermont Yankee.

On October 15, 1999, the owners of Vermont Yankee Nuclear Power Corporation accepted a bid from AmerGen Energy Company for the Vermont Yankee generating plant, intending to complete the sale before December 2000. AmerGen and the Department then negotiated a revised offer in November 2000, which was subsequently dismissed as insufficient by the VPSB in February 2001. Entergy Nuclear Inc. has also made an offer, and two other companies have indicated they would participate in an auction, if held. The plant is likely to be sold at auction, the terms and conditions of which are unknown at this time.

The Company and Central Vermont Public Service Corporation acted as lead sponsors in the construction of the Vermont Yankee Nuclear Plant, a boiling-water reactor designed by General Electric Company. The plant, which became operational in 1972, has a generating capacity of 531 MW. Vermont Yankee has entered into power contracts with its sponsor utilities, including the Company, that expire at the end of the life of the unit. Pursuant to our power contract, we are required to pay 20% of Vermont Yankee's operating expenses (including depreciation and taxes), fuel costs (including charges in respect of estimated costs of disposal of spent nuclear fuel), decommissioning expenses, interest expense and return on common equity, whether or not the Vermont Yankee plant is operating. In 1969, we sold to other Vermont utilities a share of our entitlement to the output of Vermont Yankee. Accordingly, those utilities have an obligation to pay us 2.338% of Vermont Yankee's operating expenses, fuel costs, decommissioning expenses, interest expense and return on common equity, whether or not the Vermont Yankee plant is operating.

Vermont Yankee has also entered into capital funds agreements with its sponsor utilities that expire on December 31, 2002. Under our Capital Funds Agreement, we are required, subject to obtaining necessary regulatory approvals, to provide 20% of the capital requirements of Vermont Yankee not obtained from outside sources.

In December 1996, August 1997 and July 1998, decisions were made to retire three New England nuclear units, Connecticut Yankee, Maine Yankee and Millstone 1 effective immediately, with several years remaining on each license. The NRC's most recently issued Systematic Assessment of Licensee Performance scores for Vermont Yankee are for the period January 19, 1997 to July 18, 1998. Operations, engineering, maintenance and plant support were rated good. These scores were identical to Vermont Yankee's scores for the prior 18 month-period except for plant support, which declined from superior.

During periods when Vermont Yankee power is unavailable, we incur replacement power costs in excess of those costs that we would have incurred for power purchased from Vermont Yankee. Replacement power is available to us from the ISO and through contractual arrangements with other utilities. Replacement power costs adversely affect cash flow and, absent deferral, amortization and recovery through rates, would adversely affect reported earnings. Routinely, in the case of scheduled outages for refueling, the VPSB has permitted the Company to defer, amortize and recover these excess replacement power costs for financial reporting and rate making purposes over the period until the next scheduled outage. Vermont Yankee has adopted an 18-month refueling schedule. The 2001 refueling outage is tentatively scheduled to begin June 2001, though it may occur earlier. In the case of unscheduled outages of significant duration resulting in substantial unanticipated costs for replacement power, the VPSB generally has authorized deferral, amortization and recovery of such costs.

Vermont Yankee's current estimate of costs to decommission the plant, using the 1993 FERC approved 5.4 percent escalation rate, is approximately $430 million, of which $247 million has been funded. At December 31, 2000, our portion of the net non-funded liability was $33 million, which we expect will be recovered through rates over Vermont Yankee's remaining operating life. Vermont

Yankee's current operating license expires March 2012.

During the year ended December 31, 2000, we used 803,303 MWh of Vermont Yankee energy to meet 28.8% of our retail and requirements wholesale ("Rate W") sales. The average cost of Vermont Yankee electricity in 2000 was $0.039 per KWh. Vermont Yankee's annual capacity factor for 2000 was 99.2%, compared with 90.9% in 1999, 73.6% in 1998 and 93.5% in 1997. The 1999 capacity factor was the best ever for Vermont Yankee in a year that included a refueling outage.

See Note B of Notes to Annual Report.

Hydro-Quebec

Highgate Interconnection. On September 23, 1985, the Highgate transmission facilities, which were constructed to import energy from Hydro-Quebec in Canada, began commercial operation. The transmission facilities at Highgate include a 225-MW AC-to-DC-to-AC converter terminal and seven miles of 345-kV transmission line. VELCO built and operates the converter facilities, which we own jointly with a number of other Vermont utilities.

NEPOOL/Hydro-Quebec Interconnection. VELCO and certain other NEPOOL members have entered into agreements with Hydro-Quebec which provided for the construction in two phases of a direct interconnection between the electric systems in New England and the electric system of Hydro-Quebec in Canada. The Vermont participants in this project, which has a capacity of 2,000 MW, will derive about 9.0% of the total power-supply benefits associated with the NEPOOL/Hydro-Quebec interconnection. The Company, in turn, receives about one-third of the Vermont share of those benefits.

The benefits of the interconnection include:

* access to surplus hydroelectric energy from Hydro-Quebec at competitive prices;
* energy banking, under which participating New England utilities will transmit relatively inexpensive energy to Hydro-Quebec during off-peak periods and will receive equal amounts of energy, after adjustment for transmission losses, from Hydro-Quebec during peak periods when replacement costs are higher; and
* a provision for emergency transfers and mutual backup to improve reliability for both the Hydro-Quebec system and the New England systems.

Phase I. The first phase ("Phase I") of the NEPOOL/Hydro-Quebec Interconnection consists of transmission facilities having a capacity of 690 MW that traverse a portion of eastern Vermont and extend to a converter terminal located in Comerford, New Hampshire. These facilities entered commercial operation on October 1, 1986. VETCO was organized to construct, own and operate those portions of the transmission facilities located in Vermont. Total construction costs incurred by VETCO for Phase I were $47,850,000. Of that amount, VELCO provided $10,000,000 of equity capital to VETCO through sales of VELCO preferred stock to the Vermont participants in the project. The Company purchased $3,100,000 of VELCO preferred stock to finance the equity portion of Phase I. The remaining $37,850,000 of construction cost was financed by VETCO's issuance of $37,000,000 of long-term debt in the fourth quarter of 1986 and the balance of $850,000 was financed by short-term debt.

Under the Phase I contracts, each New England participant, including the Company, is required to pay monthly its proportionate share of VETCO's total cost of service, including its capital costs. Each participant also pays a proportionate share of the total costs of service associated with those portions of the transmission facilities constructed in New Hampshire by a subsidiary of New England Electric System.

Phase II. Agreements executed in 1985 among the Company, VELCO and other NEPOOL members and Hydro-Quebec provided for the construction of the second phase ("Phase II") of the interconnection between the New England Electric System and that of Hydro-Quebec. Phase II expanded the Phase I facilities from 690 MW to 2,000 MW, and provides for transmission of Hydro-Quebec power from the Phase I terminal in northern New Hampshire to Sandy Pond, Massachusetts.

Construction of Phase II commenced in 1988 and was completed in late 1990. The Phase II facilities commenced commercial operation November 1, 1990, initially at a rating of 1,200 MW, and increased to a transfer capability of 2,000 MW in July 1991. The Hydro-Quebec-NEPOOL Firm Energy Contract provides for the import of economical Hydro-Quebec energy into New England. The Company is entitled to 3.2% of the Phase II power-supply benefits. Total construction costs for Phase II were approximately $487,000,000. The New England participants, including the Company, have contracted to pay monthly their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. As a supporting participant, the Company must make support payments under 30-year agreements. These support agreements meet the capital lease accounting requirements under SFAS 13. At December 31, 2000, the present value of the Company's obligation was approximately $6,449,000. The Company's projected future minimum payments under the Phase II support agreements are approximately $430,000 for each of the years 2001-2005 and an aggregate of $4,299,000 for the years 2006-2020.

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company, Inc. and New England Hydro-Transmission Corporation, subsidiaries of New England Electric System, in which certain of the Phase II participating utilities, including the Company, own equity interests. The Company owns approximately 3.2% of the equity of the corporations owning the Phase II facilities. During construction of the Phase II project, the Company, as an equity sponsor, was required to provide equity capital. At December 31, 2000, the capital structure of such corporations was approximately 39% common equity and 61% long-term debt. See Notes B and J of Notes to Annual Report.

At times, we request that portions of our power deliveries from Hydro-Quebec and other sources be routed through New York. Our ability to do so could be adversely affected by the proposed tariff that NEPOOL has filed with the FERC, which would reduce our allocation of capacity on transmission interfaces with New York. As a result, our ability to import power to Vermont from outside New England could be adversely affected, thereby impacting our power costs in the future. See Item 7. MD and A - Transmission Issues and Note J of Notes to Annual Report.

Hydro-Quebec Power Supply Contracts. We have several purchase power contracts with Hydro-Quebec. The bulk of our purchases are comprised of two schedules, B and C3, pursuant to a Firm Contract dated December 1987. Under these two schedules, we purchase 114.2 MW. Under an arrangement negotiated in January 1996, we received payments from Hydro-Quebec of $3,000,000 in 1996 and $1,100,000 in 1997. In accordance with such arrangement, we agreed to shift certain transmission requirements, purchase certain quantities of power and make certain minimum payments for periods in which power is not purchased. In addition, in November 1996, we entered into a Memorandum of Understanding with Hydro-Quebec under which Hydro-Quebec paid $8,000,000 to the Company in exchange for certain power purchase options. The exercise of these options in 2000 resulted in an increase of approximately $7.7 million to power supply expense to meet contractual obligations under the Company's December 1997 sell-back agreement with Hydro-Quebec. See Item 7. MD and A - Power Supply Expenses, and Notes I, J and K of Notes to Annual Report.

In 2000, we used 406,408 MWh under Schedule B, 273,088 MWh under Schedule C3, and 149,551 MWh under the HQ 9601 and 9602 arrangements to meet 29.7% of our retail and requirements wholesale sales. The average cost of Hydro-Quebec electricity in 1999 was $0.06 per KWh.

Stony Brook I. The Massachusetts Municipal Wholesale Electric Company ("MMWEC") is principal owner and operator of Stony Brook, a 352.0-MW combined-cycle intermediate generating station located in Ludlow, Massachusetts, which commenced commercial operation in November 1981. We entered into a Joint Ownership Agreement with MMWEC dated as of October 1, 1977, whereby we acquired an 8.8% ownership share of the plant, entitling us to 31.0 MW of capacity. In addition to this entitlement, we have contracted for 14.2 MW of capacity for the life of the Stony Brook I plant, for which we will pay a proportionate share of MMWEC's share of the plant's fixed costs and variable operating expenses. The three units that comprise Stony Brook I are all capable of burning oil. Two of the units are also capable of burning natural gas. The natural gas system at the plant was modified in 1985 to allow two units to operate simultaneously on natural gas.

During 2000, we used 73,433 MWh from this plant to meet 2.6% of our retail and requirements wholesale sales at an average cost of $0.064 per KWh. See Note I and K of Notes to Annual Report.

Wyman Unit #4. The W. F. Wyman Unit #4, which is located in Yarmouth, Maine, is an oil-fired steam plant with a capacity of 620 MW. Central Maine Power Company sponsored the construction of this plant. We have a joint-ownership share of 1.1% (7.1 MW) in the Wyman #4 unit, which began commercial operation in December 1978.

During 2000, we used 15,443 MWh from this unit to meet 0.6% of our retail and requirements wholesale sales at an average cost of $0.044 per kWh, based only on operation, maintenance, and fuel costs incurred during 2000. See Note I of Notes to Annual Report.

McNeil Station. The J.C. McNeil station, which is located in Burlington, Vermont, is a wood chip and gas-fired steam plant with a capacity of 53.0 MW. We have an 11.0% or 5.8 MW interest in the J. C. McNeil plant, which began operation in June 1984. In 1989, the plant added the capability to burn natural gas on an as-available/interruptible service basis.

During 2000, we used 33,569 MWh from this unit to meet 1.2% of our retail and requirements wholesale sales at an average cost of $0.053 per kWh, based only on operation, maintenance, and fuel costs incurred during 2000. See Note I of Notes to Annual Report.

Independent Power Producers. The VPSB has adopted rules that implement for Vermont the purchase requirements established by federal law in the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Under the rules, qualifying facilities have the option to sell their output to a central state-purchasing agent under a variety of long- and short-term, firm and non-firm pricing schedules. Each of these schedules is based upon the projected Vermont composite system's power costs that would be required but for the purchases from independent producers. The State purchasing agent assigns the energy so purchased, and the costs of purchase, to each Vermont retail electric utility based upon its pro rata share of total Vermont retail energy sales. Utilities may also contract directly with producers. The rules provide that all reasonable costs incurred by a utility under the rules will be included in the utilities' revenue requirements for rate-making purposes.

Currently, the State purchasing agent, Vermont Electric Power Producers, Inc. ("VEPPI"), is authorized to seek 150 MW of power from qualifying facilities under PURPA, of which our average pro rata share in 2000 was approximately 32.9% or 49.3 MW.

The rated capacity of the qualifying facilities currently selling power to VEPPI is approximately 74.5 MW. These facilities were all online by the spring of 1993, and no other projects are under development. We do not expect any new projects to come online in the foreseeable future because the excess capacity in the region has eliminated the need for and value of additional qualifying facilities.

In 2000, through our direct contracts and VEPPI, we purchased 120,000 MWh of qualifying facilities production to meet 4.3% of our retail and requirements wholesale sales at an average cost of $0.113 per KWh.

Short Term Opportunity Purchases and Sales. We have arrangements with numerous utilities and power marketers actively trading power in New England and New York under which we may make purchases or sales of power on short notice and generally for brief periods of time when it appears economic to do so. Opportunity purchases are arranged when it is possible to purchase power for less than it would cost us to generate the power with our own sources. Purchases also help us save on replacement power costs during an outage of one of our base load sources. Opportunity sales are arranged when we have surplus energy available at a price that is economic to other regional utilities at any given time. The sales are arranged based on forecasted costs of supplying the incremental power necessary to serve the sale. Prices are set so as to recover all of the forecasted fuel or production costs and to recover some, if not all, associated capacity costs.

During 2000, we purchased 757,595 MWh, meeting 27.1% of our retail and requirements wholesale sales, at an average cost of $0.044 per kWh.

Company Hydroelectric Power. The Company wholly owns and operates eight hydroelectric generating facilities located on river systems within its service area, the largest of which has a generating output of 7.8 MW.

In 2000, the Company owned hydroelectric plants provided 108,230 MWh of low-cost energy, meeting 3.9% of our retail and requirements wholesale sales at an average cost of $0.051 per kWh based on total embedded costs and maintenance. See State and Federal Regulation - Licensing.

VELCO. The Company and six other Vermont electric distribution utilities own VELCO. Since commencing operation in 1958, VELCO has transmitted power for its owners in Vermont, including power from NYPA and other power contracted for by Vermont utilities. VELCO also purchases bulk power for resale at cost to its owners, and as a member of NEPOOL, represents all Vermont electric utilities in pool arrangements and transactions. See Note B of Notes to Annual Report.

Fuel. During 2000, our retail and requirements wholesale sales were provided by the following fuel sources:

* 35.8% from hydroelectric sources (3.9% Company-owned, 0.1% NYPA, 29.5% Hydro-Quebec and 2.3% small power producers);
* 28.8% from a nuclear generating source (the Vermont Yankee nuclear plant described below);
* 2.8% from wood;
* 2.7% from oil;
* 2.2% from natural gas;
* 0.4% from wind power producers; and
* 27.3% was purchased on a short-term basis from other utilities through the Independent System Operator of New England ("ISO"), formerly the New England Power Pool ("NEPOOL").

Vermont Yankee has several requirement-based contracts for the four components (uranium, conversion, enrichment and fabrication) used to produce nuclear fuel. These contracts are executed only if the need or requirement for fuel arises. Under these contracts, any disruption of operating activity would allow Vermont Yankee to cancel or postpone deliveries until actually required. The contracts extend through various time periods and contain clauses to allow Vermont Yankee the option to extend the agreements. Negotiation of new contracts and renegotiations of existing contracts routinely occurs, often focusing on one of the four components at a time. The 1999 reload cost approximately $20.8 million. Future reload costs will depend on market and contract prices

On January 20, 1997, Vermont Yankee entered into an agreement with a former uranium supplier whereby the supplier could opt to terminate a production purchase agreement dated August 4, 1978. Although there had been no transactions under the production purchase agreement for several years, Vermont Yankee maintained certain financial rights. In consideration for the option to terminate the production purchase agreement and the subsequent exercise of the option, Vermont Yankee received $600,000 in 1997, which was recorded as an offset to nuclear fuel expense. The potential future payments over a ten-year period range from zero to $2.4 million. No payments were received in 2000 under this agreement. Due to the uncertainty of this transaction, any benefits received will be recorded on a cash basis.

Vermont Yankee has a contract with the United States Department of Energy ("DOE") for the permanent disposal of spent nuclear fuel. Under the terms of this contract, in exchange for the one-time fee discussed below and a quarterly fee of 1 mil per kWh of electricity generated and sold, the DOE agrees to provide disposal services when a facility for spent nuclear fuel and other high-level radioactive waste is available, which is required by contract to be prior to January 31, 1998. The actual date for these disposal services is expected to be delayed many years. DOE currently estimates that a permanent disposal facility will not begin operation before 2010. A DOE temporary disposal site may be provided in a few years, but no decision has been made to proceed on providing a temporary disposal site at this time.

The DOE contract obligates Vermont Yankee to pay a one-time fee of approximately $39.3 million for disposal costs for all spent fuel discharged through April 7, 1983. Although such amount has been collected in rates from the Vermont Yankee participants, Vermont Yankee has elected to defer payment of the fee to the DOE as permitted by the DOE contract. The fee must be paid no later than the first delivery of spent nuclear fuel to the DOE. Interest accrues on the unpaid obligation based on the thirteen-week Treasury Bill rate and is compounded quarterly. Through 2000 Vermont Yankee accumulated approximately $108.0 million in an irrevocable trust to be used exclusively for settling this obligation at some future date, provided the DOE complies with the terms of the aforementioned contract.

We do not maintain long-term contracts for the supply of oil for our wholly-owned oil-fired peak generating stations (80 MW). We did not experience difficulty in obtaining oil for our own units during 2000, and, while no assurance can be given, we do not anticipate any such difficulty during 2001. None of the utilities from which we expect to purchase oil- or gas-fired capacity in 2001 has advised us of grounds for doubt about maintenance of secure sources of oil and gas during the year.

Wood for the McNeil plant is furnished to the Burlington Electric Department from a variety of sources under short-term contracts ranging from several weeks' to six months' duration. The McNeil plant used 299,246 tons of wood chips and mill residue, 1,146,045 gallons of fuel oil, and 1.044 billion cubic feet of natural gas in 2000. The McNeil plant, assuming any needed regulatory approvals are obtained, is forecasting year 2001 consumption of wood chips to be 300,000 tons, fuel oil of 200,000 gallons and natural gas consumption of 26 million cubic feet.

The Stony Brook combined-cycle generating station is capable of burning either natural gas or oil in two of its turbines. Natural gas is supplied to the plant subject to its availability. During periods of extremely cold weather, the supplier reserves the right to discontinue deliveries to the plant in order to satisfy the demand of its residential customers. We assume, for planning and budgeting purposes, that the plant will be supplied with gas during the months of April through November, and that it will run solely on oil during the months of December through March. The plant maintains an oil supply sufficient to meet approximately one-half of its annual needs.

Wind Project. The Company was selected by the DOE and the Electric Power Research Institute ("EPRI") to build a commercial scale wind-powered facility. The DOE and EPRI provided partial funding for the wind project of approximately $3.9 million. The net cost to the Company of the project, located in the southern Vermont town of Searsburg, was $7.8 million. The eleven wind turbines have a rating of 6 MW and were commissioned July 1, 1997.

In 2000, the plant provided 12,246 MWh, meeting 0.4% of the Company's retail and requirements wholesale sales at an average cost of $0.07 per kWh.

ENERGY EFFICIENCY

In 2000, GMP focused its energy efficiency services on transferring its programs that encouraged customers to install energy efficient equipment to the Energy Efficiency Utility created by the VPSB in 1999 to manage energy efficiency programs for all utilities in Vermont. The Company's customers are now billed a separate EEU charge that we remit directly to the EEU. During the past eight years the Company's efficiency programs have achieved a cumulative annual savings of 89,000 megawatthours, saving approximately $7.9 million per year for our customers. In 2000, we spent approximately $305,000 on energy efficiency programs.

RATE DESIGN

The Company seeks to design rates to encourage the shifting of electrical use from peak hours to off-peak hours. Since 1976, we have offered optional time-of-use rates for residential and commercial customers. Currently, approximately 2,160 of the Company's residential customers continue to be billed on the original 1976 time-of-use rate basis. In 1987, the Company received regulatory approval for a rate design that permitted it to charge prices for electric service that reflected as accurately as possible the cost burden imposed by each customer class. The Company's rate design objectives are to provide a stable pricing structure and to accurately reflect the cost of providing electric services. This rate structure helps to achieve these goals. Since inefficient use of electricity increases its cost, customers who are charged prices that reflect the cost of providing electrical service have real incentives to follow the most efficient usage patterns. Included in the VPSB's order approving this rate design was a requirement that the Company's largest customers be charged time-of-use rates on a phased-in basis by 1994. At December 31, 2000, approximately 1,360 of the Company's largest customers, comprising 52% of retail revenues, continue to receive service on mandatory time-of-use rates.

In May 1994, the Company filed its current rate design with the VPSB. The parties, including the Department, IBM and a low-income advocacy group, entered into a settlement that was approved by the VPSB on December 2, 1994. Under the settlement, the revenue allocation to each rate class was adjusted to reflect class-by-class cost changes since 1987, the differential between the winter and summer rates was reduced, the customer charge was increased for most classes, and usage charges were adjusted to be closer to the associated marginal costs.

No modifications to base rate redesign have taken place since the VPSB Order issued on December 2, 1994, however, as previously noted, the VPSB Settlement Order of January 2001 eliminates seasonal rate differentials effective April 2001.

DISPATCHABLE AND INTERRUPTIBLE SERVICE CONTRACTS

In 2000, we had 28 dispatchable power contracts: 20 contracts were year-round, while the 8 seasonal contracts include two major ski areas. The dispatchable portion of the contracts allows customers to purchase electricity during times designated by the Company when low cost power is available. The customer's demand during these periods is not considered in calculating the monthly billing. This program enables the Company and the customers to benefit from load control. We shift load from our high cost peak periods and the customer uses inexpensive power at a time when its use provides maximum value. These programs are available by tariff for qualifying customers.

CONSTRUCTION AND CAPITAL REQUIREMENTS

Our capital expenditures for 1998 through 2000 and projection for 2001 are set forth in Item 7. Management's Discussion And Analysis Of Financial Condition and Results Of Operations - Liquidity and Capital Resources-Construction. Construction projections are subject to continuing review and may be revised from time-to-time in accordance with changes in the Company's financial condition, load forecasts, the availability and cost of labor and materials, licensing and other regulatory requirements, changing environmental standards and other relevant factors.

For the period 1998-2000, internally generated funds, after payment of dividends, provided approximately 59 percent of total capital requirements for construction, sinking fund obligations and other requirements. Internally generated funds provided 40 percent of such requirements for 2000. We anticipate that for 2001, internally generated funds will provide approximately 90 percent of total capital requirements for regulated operations, the remainder to be derived from bank loans.

In connection with the foregoing, see Item 7. MD and A - Liquidity and

Capital Resources.

ENVIRONMENTAL MATTERS

We had been notified by the Environmental Protection Agency ("EPA") that we were one of several potentially responsible parties for clean up at the Pine Street Barge Canal site in Burlington, Vermont. In September 1999, we negotiated a final settlement with the United States, the State of Vermont, and other parties over terms of a Consent Decree that covers claims addressed in earlier negotiations and implementation of the selected remedy. In October 1999, the federal district court approved the Consent Decree that addresses claims by the EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site. For information regarding the Pine Street Canal site and other environmental matters see Item 7. MD and - Environmental Matters, and Note I of Notes to Annual Report.

UNREGULATED BUSINESSES

In 1998, we sold the assets of our wholly owned subsidiary, Green Mountain Propane Gas Company. In 1999, Green Mountain Resources, Inc. sold its remaining interest in Green Mountain Energy Resources to Green Funding I. During 1999, the Company discontinued operations of Mountain Energy, Inc. ("MEI"), a subsidiary of the Company that invests in wastewater, energy efficiency and generation businesses. The loss in 2000 reflects the sale of most of MEI's remaining energy assets and the current estimated costs of winding down MEI's wastewater businesses. For information regarding our remaining unregulated businesses, see Item 7. MD and A - Future Outlook - Unregulated Businesses.

EXECUTIVE OFFICERS

The Executive Officers names, ages, and positions of the Company as of March 15, 2001 are:

Nancy Rowden Brock 45

Vice President, Chief Financial Officer and Treasurer since December 1998, and Secretary since August 1999. Chief Corporate Strategic Planning Officer from March 1998 to December 1998. Prior to joining the Company, she was Chief Financial Officer of SAL, Inc., 1997; and Senior Vice President, Chief Financial Officer and Treasurer for the Chittenden Corporation from 1988 to 1996.

Christopher L. Dutton 52

President, Chief Executive Officer of the Company and Chairman of the Executive Committee of the Company since August 1997. Vice President, Finance and Administration, Chief Financial Officer and Treasurer from 1995 to August 1997. Vice President and General Counsel from 1993 to January 1995. Vice President, General Counsel and Corporate Secretary from 1989 to 1993.

Robert J. Griffin 44

Controller since October 1996. Manager of General Accounting from 1990 to 1996.

Walter S. Oakes 54

Vice President-Field Operations since August 1999. Assistant Vice President-Customer Operations from June 1994 to August 1999. Assistant Vice President, Human Resources from August 1993 to June 1994. Assistant Vice President-Corporate Services from 1988 to 1993.

Mary G. Powell 40

Senior Vice President-Customer and Organizational Development since

December 1999. Vice President-Administration from February 1999 through December 1999. Vice President, Human Resources and Organizational Development from March 1998 to February 1999. Prior to joining the Company, she was President of HRworks, a human resources management firm, from January 1997 to March 1998. From 1992 to January 1997, she worked for KeyCorp in Vermont, most recently as Senior Vice President Community Banking. At KeyCorp, she also served as Vice President Administration and Vice President of Human Resources.

Stephen C. Terry 58

Senior Vice President-Government and Legal Relations since August 1999. Senior Vice President, Corporate Development from August 1997 to August 1999. Vice President and General Manager, Retail Energy Services from 1995 to August 1997. Vice President-External Affairs from 1991 to January 1995.

Jonathan H. Winer 49

President of Mountain Energy, Inc. since March 1997. Vice President and Chief Operating Officer of Mountain Energy, Inc. from 1989 to March 1997. Resigned effective January 17, 2001.

Officers are elected by the Board of Directors of the Company and its wholly-owned subsidiaries, as appropriate, for one-year terms and serve at the pleasure of such boards of directors.

ITEM 2. PROPERTY

GENERATING FACILITIES

Our Vermont properties are located in five areas and are interconnected by transmission lines of VELCO and New England Power Company. We wholly own and operate eight hydroelectric generating stations with a total nameplate rating of 36.1 MW and an estimated claimed capability of 35.7 MW. We also own two gas-turbine generating stations with an aggregate nameplate rating of 59.9 MW and an estimated aggregate claimed capability of 73.2 MW. We have two diesel generating stations with an aggregate nameplate rating of 8.0 MW and an estimated aggregate claimed capability of 8.6 MW. We also have a wind generating facility with a nameplate rating of 6.1 MW.

We also own:

* 17.9% of the outstanding common stock, and are entitled to 17.662% (93.8 MW of a total 531 MW) of the capacity, of Vermont Yankee,
* 1.1% (7.1 MW of a total 620 MW) joint-ownership share of the Wyman #4 plant located in Maine,
* 8.8% (31.0 MW of a total 352 MW) joint-ownership share of the Stony Brook I intermediate units located in Massachusetts, and
* 11.0% (5.8 MW of a total 53 MW) joint-ownership share of the J.C. McNeil wood-fired steam plant located in Burlington, Vermont.

See Item 1. Business - Power Resources for plant details and the table hereinafter set forth for generating facilities presently available.

TRANSMISSION AND DISTRIBUTION

The Company had, at December 31, 2000, approximately 1.5 miles of 115 kV transmission lines, 10.5 miles of 69 kV transmission lines, 5.4 miles of 44 kV and 284.6 miles of 34.5 kV transmission lines. Our distribution system includes approximately 2,705 miles of overhead lines of 2.4 kV to 34.5 kV, and about 461 miles of underground cable of 2.4 kV to 34.5 kV. At such date, we owned approximately 158,820 kVa of substation transformer capacity in transmission substations, 569,750 kVa of substation transformer capacity in distribution substations and 1,085,000 kVa of transformers for step-down from distribution to customer use.

The Company owns 34.8% of the Highgate transmission inter-tie, a 225-MW converter and transmission line used to transmit power from Hydro-Quebec.

We also own 29.5% of the common stock and 30% of the preferred stock of

VELCO, which operates a high-voltage transmission system interconnecting electric utilities in the State of Vermont.

PROPERTY OWNERSHIP

The Company's wholly-owned plants are located on lands that we own in fee. Water power and floodage rights are controlled through ownership of the necessary land in fee or under easements.

Transmission and distribution facilities that are not located in or over public highways are, with minor exceptions, located either on land owned in fee or pursuant to easements which, in nearly all cases, are perpetual. Transmission and distribution lines located in or over public highways are so located pursuant to authority conferred on public utilities by statute, subject to regulation by state or municipal authorities.

INDENTURE OF FIRST MORTGAGE

The Company's interests in substantially all of its properties and franchises are subject to the lien of the mortgage securing its First Mortgage Bonds.

The Company has also provided a second mortgage, lien and security interest in the collateral pledged under the first mortgage bond indenture to two banks participating in the Company's revolving credit agreement with Fleet National Bank and Citizens Bank of Massachusetts.

GENERATING FACILITIES OWNED

The following table gives information with respect to generating facilities presently available in which the Company has an ownership interest. See also Item 1. Business - Power Resources.

	Location	Name	Fuel	Winter Capability MW(1)	
Wholly Owned					
Hydro	Middlesex, VT	Middlesex #2	Hydro	3.3	
Hydro	Marshfield, VT	Marshfield #6	Hydro	4.9	
Hydro	Vergennes, VT	Vergennes #9	Hydro	2.1	
Hydro	W. Danville, VT	W. Danville #15	Hydro	1.1	
Hydro	Colchester, VT	Gorge #18	Hydro	3.3	
Hydro	Essex Jct., VT	Essex #19	Hydro	7.8	
Hydro	Waterbury, VT	Waterbury #22	Hydro	5.0	(4)
Hydro	Bolton, VT	DeForge #1	Hydro	7.8	
Diesel.	Vergennes, VT	Vergennes #9	Oil	4.2	
Diesel.	Essex Jct., VT	Essex #19	Oil	4.4	
Gas	Berlin, VT	Berlin #5	Oil	56.6	
Turbine	Colchester, VT	Gorge #16	Oil	16.1	
Wind.	Searsburg, VT	Searsburg	Wind	1.2	
Jointly Owned					
Steam	Vernon, VT	Vermont Yankee	Nuclear	93.8	(2)
Steam	Yarmouth, ME	Wyman #4	Oil	7.1	
Steam	Burlington, VT	McNeil	Wood/Gas	6.6	(3)
Combined.	Ludlow, MA	Stony Brook #1	Oil/Gas	31.0	(2)
Total Winter Capability				256.3	

(1) Winter capability quantities are used since the Company's peak usage occurs during the winter months. Some unit ratings are reduced in the summer months due to higher ambient temperatures. Capability shown includes capacity and associated energy sold to other utilities.

(2) For a discussion of the impact of various power supply sales on the availability of generating facilities, see Item 1. Business - Power Resources.

(3) The Company's entitlement in McNeil is 5.8 MW. However, we receive up to 6.6 MW as a result of other owners' losses on this system.

(4) Reservoir has been drained, dam awaiting repairs by Army Corps of Engineers.

CORPORATE HEADQUARTERS

The Company terminated an operating lease for its corporate headquarters building and two of its service center buildings in the first quarter of 1999. During 1998, the Company recorded a loss of approximately $1.9 million before applicable income taxes to reflect the probable loss resulting from this transaction. The Company sold its corporate headquarters building in 1999, but retained ownership of the two service centers.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in several legal proceedings, the outcome of which will significantly affect the viability and or potential profitability of the Company. The most significant legal proceeding is arbitration about Hydro-Quebec's non-delivery of power as a result of the January 1998 ice storm in eastern North America. See the discussion under Item 7. MD and A - Environmental Matters, Rate Matters, and Note I of the Notes to Annual Report.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Outstanding shares of the Common Stock are listed and traded on the New York Stock Exchange under the symbol GMP. The following tabulation shows the high and low sales prices for the Common Stock on the New York Stock Exchange during 1999 and 2000:

		HIGH	LOW
1999	$.	$	
	First Quarter.	11 3/16	9 3/4
	Second Quarter	11 5/16	8 11/16
	Third Quarter.	14	10 1/4
	Fourth Quarter	10 1/4	7 1/8
2000			
	First Quarter.	9	6 9/16
	Second Quarter	8 1/2	6 5/8
	Third Quarter.	8 3/4	7 3/8
	Fourth Quarter	14 3/4	7 9/16

The number of common stockholders of record as of March 21, 2001 was 6,050.

Quarterly cash dividends were paid as follows during the past two years:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
1999	$ 0.1375	$ 0.1375	$ 0.1375	$ 0.1375
2000	$ 0.1375	$ 0.1375	$ 0.1375	$ 0.1375

Dividend Policy On November 23, 1998, the Company's Board of Directors announced a reduction in the quarterly dividend from $0.275 per share to $0.1375 per share on the Company's common stock. The current indicated annual dividend is $0.55 per share of common stock.

Our current dividend policy reflects changes affecting the electric utility industry, which is moving away from the traditional cost-of-service regulatory model to a competition based market for power supply.

The current environment prompted us to reassess the appropriateness of our traditional dividend policy. Historically, we based our dividend policy on the continued validity of three assumptions: The ability to achieve earnings growth, the receipt of an allowed rate of return that accurately reflects our cost of capital, and the retention of our exclusive franchise. The Company's Board of Directors will continue to assess and adjust the dividend, when appropriate, as the Vermont electric industry evolves towards competition. In addition, if other events beyond our control cause the Company's financial situation to deteriorate further, the Board of Directors will also consider whether the current dividend level is appropriate or if the dividend should be reduced or eliminated. See Item 7. MD and A - Future Outlook, Competition and Restructuring, and Note C of Notes to Annual Report. for a discussion of dividend restrictions.

ITEM 6. SELECTED FINANCIAL DATA

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31,

	2000	1999	1998	1997	1996
In thousands, except per share data					
Operating Revenues	$277,326	$251,048	$184,304	$179,323	$179,00
Operating Expenses	272,066	243,102	178,832	163,808	162,88
Operating Income	5,260	7,946	5,472	15,515	16,12

Other Income					
AFUDC - equity	284	134	104	357	17
Other	2,422	3,319	1,509	1,074	1,73
Total other income	2,706	3,453	1,613	1,431	1,91
Interest Charges					
AFUDC - borrowed	(228)	(91)	(131)	(315)	(46
Other	7,485	7,274	8,007	7,965	7,86
Total interest charges	7,257	7,183	7,876	7,650	7,39
Net Income (Loss) from continuing operations before preferred dividends	709	4,216	(791)	9,296	10,64
Net Income (Loss) from discontinued operations, including provisions for loss on disposal	(6,549)	(7,279)	(2,086)	142	1,31
Dividends on Preferred Stock	1,014	1,155	1,296	1,433	1,01
Net Income (Loss)Applicable to Common Stock	$ (6,854)	$ (4,218)	$ (4,173)	$ 8,005	$ 10,94
Common Stock Data					
Earnings per share-continuing operations	$ (0.06)	$ 0.57	$ (0.40)	$ 1.54	$ 1.9
Earnings per share-discontinued operations	$ (1.19)	$ (1.36)	$ (0.40)	$ 0.03	$ 0.2
Earnings per share-basic and diluted	$ (1.25)	$ (0.79)	$ (0.80)	$ 1.57	$ 2.2
Cash dividends declared per share	$ 0.55	$ 0.55	$ 0.96	$ 1.61	$ 2.1
Weighted average shares outstanding	5,491	5,361	5,243	5,112	4,93

FINANCIAL CONDITION AS OF DECEMBER 31

In thousands	2000	1999	1998	1997	1996
ASSETS					
Utility Plant, Net	$194,672	$192,896	$195,556	$196,720	$189,853
Other Investments	20,730	20,665	20,678	21,997	20,634
Current Assets	53,652	33,238	35,700	29,125	30,901
Deferred Charges	46,036	41,853	35,576	35,831	43,224
Non-Utility Assets	1,518	11,099	27,314	42,060	39,927
Total Assets	$316,608	$299,751	$314,824	$325,733	$324,539
CAPITALIZATION AND LIABILITIES					
Common Stock Equity	$ 92,044	$100,645	$106,755	$114,377	$111,554
Redeemable Cumulative Preferred Stock	12,795	14,435	16,085	17,735	19,310
Long-Term Debt, Less Current Maturities	72,100	81,800	88,500	93,200	94,900
Capital Lease Obligation	6,449	7,038	7,696	8,342	9,006
Current Liabilities	68,109	36,708	28,825	25,286	21,037
Deferred Credits and Other	61,794	59,125	59,889	53,723	54,968
Non-Utility Liabilities	3,317	-	7,074	13,070	13,764

Total Capitalization and Liabilities.	$316,608	$299,751	$314,824	$325,733	$324,539

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

In this section, we explain the general financial condition and the results of operations for Green Mountain Power Corporation (the "Company") and its subsidiaries. This explanation includes:

* factors that affect our business;
* our earnings and costs in the periods presented and why they changed between periods;
* the source of our earnings;
* our expenditures for capital projects and what we expect they will be in the future;
* where we expect to get cash for future capital expenditures; and
* how all of the above affects our overall financial condition.

There are statements in this section that contain projections or estimates and that are considered to be forward-looking as defined by the Securities and Exchange Commission (the "SEC"). In these statements, you may find words such as believes, expects, plans, or similar words. These statements are not guarantees of our future performance. There are risks, uncertainties and other factors that could cause actual results to be different from those projected. Some of the reasons the results may be different are discussed under "Future Outlook", "Transmission Issues", "Environmental Matters", "Rates" and "Liquidity and Capital Resources" in this section, and include:

* regulatory and judicial decisions or legislation;
* weather;
* energy supply and demand and pricing;
* contractual commitments;
* availability, terms, and use of capital;
* general economic and business environment;
* nuclear and environmental issues; and
* industry restructuring and cost recovery (including stranded costs).

These forward-looking statements represent our estimates and assumptions only as of the date of this report.

EARNINGS SUMMARY

On January 23, 2001, the Vermont Public Service Board ("VPSB") issued an order (the "Settlement Order") approving a settlement between the Company and the Vermont Department of Public Service (the "Department") that grants the Company an immediate 3.42 percent rate increase, and allows full recovery of power supply costs under the Hydro-Quebec Vermont Joint Owners ("VJO") contract. The Settlement Order paves the way for restoration of the Company's investment grade status (See "Retail Rate Cases" and "Liquidity and Capital Resources" in this section)and gives the Company an opportunity to earn its allowed rate of return during 2001, or approximately $1.96 per share. During 2000, the Company lost $1.25 per share of common stock, compared with a loss per share of $0.79 in 1999 and a loss per share of $0.80 in 1998. The 2000 loss represents a negative return on average common equity of 7.1 percent. The return on average common equity was negative 4.0 percent in 1999 and negative 3.8 percent in 1998. The loss from continuing operations was $0.06 per share in 2000, compared with earnings of $0.57 per share in 1999 and a loss of $0.40 in 1998. Certain subsidiary operations, classified as discontinued in 1999, lost $1.19 per share in 2000, compared with a loss of $1.36 per share in 1999 and a loss of $0.40 per share in 1998.

The consolidated loss in 2000 was greater than the prior year consolidated loss as a result of the VPSB Settlement Order that disallowed recovery of $3.2 million or $0.35 per share in regulatory litigation costs and from higher power supply costs that were not recovered in rates. Power supply expense increased $30.2 million in 2000, outpacing revenue growth of $26.3 million and reductions in depreciation and amortization expense of $0.9 million.

The 1999 improvement in results from continuing operations was primarily due to three factors:

* retail operating revenues increased by $15.1 million, reflecting a 5.5 percent temporary rate increase that went into effect on December 15, 1998, and a 3.9 percent increase in sales to commercial and industrial customers in 1999;
* operating costs were $3.7 million lower in 1999 due to the Company's termination of its corporate headquarters lease, reduced costs associated with the Company's headquarters facilities and lower payroll expense reflecting mid-year reductions in the number of employees; and
* results for 1998 reflected pretax charges of $9.8 million in disallowed Hydro-Quebec power costs for both 1998 and 1999, compared with disallowed power costs of $7.5 million for 2000 recorded in 1999.

The 1999 earnings improvement was partially offset by:

* a $4.3 million increase in the capacity costs in 1999 associated with our long-term Hydro-Quebec power supply contract;
* an increase in the costs of short-term power following the deregulation of energy markets in New England, as well as an increase in our costs to serve increased local loads and an increase of approximately $5.4 million to supply power to meet contractual obligations under the Company's December 1997 sell-back agreement with Hydro-Quebec; and
* a $1.9 million increase in capacity costs associated with a contract with Vermont Yankee Nuclear Power Corporation ("Vermont Yankee").

The Company's discontinued operations lost $1.19 in 2000 compared with a loss of $1.36 in 1999. During 1999, the Company discontinued operations of Mountain Energy, Inc. ("MEI"), a subsidiary of the Company that invests in wastewater, energy efficiency and generation businesses. The loss in 2000 reflects the sale of most of MEI's remaining energy assets and the current estimated costs of winding down MEI's wastewater businesses. During January 2001, MEI changed its name to Northern Water Resources, Inc. ("NWR").

FUTURE OUTLOOK

COMPETITION AND RESTRUCTURING-The electric utility business is experiencing rapid and substantial changes. These changes are the result of the following trends:

* disparity in electric rates, transmission, and generating capacity among and within various regions of the country;
* improvements in generation efficiency;
* increasing demand for customer choice; and
* new regulations and legislation intended to foster competition, also known as restructuring.

Electric utilities historically have had exclusive franchises for the retail sale of electricity in specified service territories. As a result, competition for retail customers has been limited to:

* competition with alternative fuel suppliers, primarily for heating and cooling;
* competition with customer-owned generation; and
* direct competition among electric utilities to attract major new facilities to their service territories.

These competitive pressures have led the Company and other utilities to offer, from time to time, special discounts or service packages to certain large customers.

In certain states across the country, including all the New England states except Vermont, legislation has been enacted to allow retail customers to choose their electricity suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems (also known as retail wheeling). Increased pressure in the electric utility industry may restrict the Company's ability to charge energy prices sufficient to recover embedded costs, such as the cost of purchased power obligations or of generation facilities owned by the Company. The amount by which such costs might exceed market prices is commonly referred to as stranded costs.

Regulatory and legislative authorities at the federal level and in some states, including Vermont where legislation has not been enacted, are considering whether, when and how to facilitate competition for electricity sales at the wholesale and retail levels. Recent difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards deregulation in Vermont. However, in the future, the Vermont General Assembly through legislation, or the VPSB through a subsequent report, action or proceeding, may allow customers to choose their electric supplier. If this happens without providing for recovery of a significant portion of the costs associated with our power supply obligations and other costs of providing vertically integrated service, the Company's franchise, including our operating results, cash flows and ability to pay dividends at the current level, would be adversely affected.

ITEM 7A. RISK FACTORS-The major risk factors for the Company arising from electric industry restructuring, including risks pertaining to the recovery of stranded costs, are:

* regulatory and legal decisions;
* cost and amount of default service responsibility;
* the market price of power; and
* the amount of market share retained by the Company.

There can be no assurance that any potential future restructuring plan ordered by the VPSB, the courts, or through legislation will include a mechanism that would allow for full recovery of our stranded costs and include a fair return on those costs as they are being recovered. If laws are enacted or regulatory decisions are made that do not offer an adequate opportunity to recover stranded costs, we believe we have compelling legal arguments to challenge such laws or decisions.

The largest category of our potential stranded costs is future costs under long-term power purchase contracts, which, based on current forecasts, are above-market. The magnitude of our stranded costs is largely dependent upon the future market price of power. We have discussed various market price scenarios with interested parties for the purpose of identifying stranded costs. Preliminary market price assumptions, which are likely to change, have resulted in estimates of the Company's stranded costs of between $74 million and $162 million. We intend to aggressively pursue mitigation efforts in order to minimize the amount and maximize the recovery of these costs.

If retail competition is implemented in Vermont, we cannot predict what the impact would be on the Company's revenues from electricity sales. Historically, electric utility rates have been based on a utility's cost of service. As a result, electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards Number 71, ("SFAS 71"), Accounting for the Effects of Certain Types of Regulation, allows regulated entities, in appropriate circumstances, to establish regulatory assets and liabilities, and thereby defer the income statement impact of certain costs and revenues that are expected to be realized in future rates. The Company has established approximately $47.5 million of net regulatory assets and liabilities under SFAS 71.

The Company currently complies with the provisions of SFAS 71. In the event the Company determines that it no longer meets the criteria for following SFAS 71, the accounting impact would be an extraordinary, non-cash charge to operations of an amount that would be material. Factors that could give rise to the discontinuance of SFAS 71 include:

* deregulation;

* a change in the regulator's approach to setting rates from cost-based regulation to another form of regulation;
* increasing competition that limits our ability to sell utility services or products at rates that will recover costs; and
* regulatory actions that limit rate relief to a level insufficient to recover costs.

Under Statement of Financial Accounting Standards Number 5 ("SFAS 5"), Accounting for Contingencies, the enactment of restructuring legislation or issuance of a regulatory order containing provisions that do not allow for the recovery of above-market power costs would require the Company to estimate and record losses immediately, on an undiscounted basis, for any above-market power purchase contracts and other costs which are probable of not being recoverable from customers, to the extent that those costs are estimable.

We are unable to predict what form future legislation, if passed, or an order if issued, will take, and we cannot predict if or to what extent SFAS 71 will continue to be applicable in the future. In addition, members of the staff of the Securities and Exchange Commission have raised questions concerning the continued applicability of SFAS 71 to certain other electric utilities facing restructuring.

We cannot predict whether restructuring legislation enacted by the Vermont General Assembly or any subsequent report or actions of, or proceedings before, the VPSB or the Vermont General Assembly would have a material adverse effect on our operations, financial condition or credit ratings. The failure to recover a significant portion of our purchased power costs, or to retain and attract customers in a competitive environment, would likely have a material adverse effect on our business, including our operating results, cash flows and ability to pay dividends at current levels.

Inherent in our market risk sensitive instruments and positions is the potential loss arising from adverse changes in our commodity prices. Restructuring of the wholesale market for electricity has brought increased price volatility to our power supply markets.

The price of electricity is subject to fluctuations resulting from changes in supply and demand. To reduce price risk caused by these market fluctuations, we have established a policy to hedge (through the utilization of derivatives) our supply and related purchase and sales commitments, as well as our anticipated purchase and sales. Because the commodities covered by these derivatives are substantially the same commodities that the Company buys and sells in the physical market, no special correlation studies other than monitoring the degree of convergence between the derivative and cash markets, are deemed necessary. Changes in market value of derivatives have a high correlation to the price changes of the hedged commodities.

A sensitivity analysis has been prepared to estimate the exposure to the market price risk of our electricity commodity positions. Our daily net commodity position consists of purchased electric capacity. The table below presents market risk estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in prices. Actual results may differ materially from the table.

Commodity Price Risk	At December 31, 2000	
	Fair Value	Market Risk
	(in thousands)	
Highest long position.	$ 173,741	$ 17,374
Highest short position	$ 201,608	$ 20,161
Average short position	$ 27,867	$ 2,787

Risk factors associated with the discontinuation of MEI operations include the outcome of warranty litigation, and future cash requirements necessary to minimize costs of winding down wastewater operations. Several municipalities using wastewater treatment equipment provided by Micronair, LLC, a wholly owned subsidiary of MEI, have commenced or threatened litigation against Micronair. The ultimate loss remains subject to the disposition of remaining MEI assets and liabilities, and could exceed the amounts recorded.

UNREGULATED BUSINESSES

In 2000, we significantly reduced our investment in unregulated businesses, continuing the process we began in June 1999, when we decided to sell or otherwise dispose of the assets of MEI, and report its results as loss from operations of a discontinued segment. MEI, which invested in energy generation, energy efficiency and waste water treatment projects, lost $6.5 million in 2000, compared with a loss of $7.3 million in 1999. The 2000 loss results primarily from provisions to recognize present and estimated future losses from the sale of MEI's remaining businesses, including anticipated operating losses.

Green Mountain Resources, Inc. ("GMRI") was formed in April 1996 to explore opportunities in the emerging competitive retail energy market. In 2000, GMRI earned $19,000 compared with earnings of $583,000 in 1999. GMRI's earnings in 1999 were primarily due to the sale of its remaining interest in Green Mountain Energy Resources ending operations for this subsidiary.

The Company's unregulated rental water heater business earned $498,000 in 2000, essentially unchanged from 1999's net income of $500,000. Both 2000 and 1999 results contributed earnings of $0.09 per share to the Company's consolidated results.

RESULTS OF OPERATIONS

OPERATING REVENUES AND MWH SALES-Operating revenues and megawatthour ("MWh") sales for the years ended 2000, 1999 and 1998 consisted of:

	Years ended December 31, 2000	1999	1998
(dollars in thousands)			
Operating Revenues			
Retail.	$ 188,849	$ 179,997	$ 164,855
Sales for Resale. . .	85,428	68,305	16,529
Other	3,049	2,746	2,920
Total Operating Revenues.	$ 277,326	$ 251,048	$ 184,304
MWH Sales-Retail.	1,947,857	1,900,188	1,839,522
MWH Sales for Resale. . .	2,575,657	2,172,849	543,846
Total MWH Sales	4,523,514	4,073,037	2,383,368

Average Number of Customers

	Years ended December 31, 2000	1999	1998
Residential	72,424	71,515	71,301
Commercial and Industrial	12,769	12,461	12,193
Other	65	66	70
Total Number of Customers. .	85,258	84,042	83,564

Differences in operating revenues were due to changes in the following:

Change in Operating Revenues (In thousands)	1999 to 2000	1998 to 1999
Retail Rates.	$ 4,230	$ 9,395
Retail Sales Volume	4,622	5,747
Resales and Other Revenues. . .	17,426	51,602
Increase in Operating Revenues.	$26,278	$66,744

In 2000, total electricity sales increased 11.1 percent due principally to sales for resale executed pursuant to the Morgan Stanley Capital Group, Inc. ("MS") agreement, described in more detail below under the headings "Power Supply Expense" and "Power Contract Commitments". Total operating revenues increased $26.3 million or 10.5 percent primarily for the same reason. Total retail revenues increased $8.9 million or 4.9 percent in 2000 primarily due to:

* a 3.0 percent retail rate increase that went into effect January 2000; and
* a 2.6 percent increase in sales of electricity to both our commercial and industrial and our residential customers resulting primarily from customer growth and load growth for our largest customer.

In 1999, total electricity sales increased 70.9 percent due principally to sales for resale executed pursuant to the MS agreement. Total operating revenues increased $66.7 million or 36.2 percent in 1999 for the same reason. Total retail revenues increased $15.1 million or 9.2 percent in 1999 primarily due to:

* a 5.5 percent retail rate increase for service rendered on or after December 15, 1998;
* a 3.9 percent increase in sales of electricity to our commercial and industrial customers resulting from customer growth and increased use of air conditioning during the spring and summer months; and
* a 3.3 percent increase in sales of electricity to residential customers, a

result of customer growth and a warmer than normal summer.

International Business Machines ("IBM"), the Company's single largest customer, operates manufacturing facilities in Essex Junction, Vermont. IBM's electricity requirements for its main plant and an adjacent plant accounted for 11.2, 11.8, and 14.7 percent of the Company's total operating revenues in 2000, 1999, and 1998, respectively, and 16.5, 16.4 and 17.1 percent of the Company's retail operating revenues in 2000, 1999, and 1998, respectively. No other retail customer accounted for more than one percent of the Company's revenue in any year.

Since 1995, the Company has had agreements with IBM with respect to electricity sales above agreed-upon base-load levels. On December 8, 2000, the VPSB approved a new three-year agreement between the Company and IBM, ending December 31, 2003. The price of power for the renewal period of the agreement is above our marginal costs of providing incremental service to IBM.

POWER SUPPLY EXPENSES-Our inability to recover our power supply costs has been the primary reason for the poor performance of the Company's common stock over the past three years. The Settlement Order removes this obstacle by allowing the Company rate recovery of its estimated power supply costs for 2001. Furthermore, the Settlement Order allows the Company to use approximately $6.0 million in rate levelization cash flow to achieve its allowed rate of return in 2001 and 2002, and, together with the extension of our power supply agreement with MS, provides us an opportunity to recover our power supply costs in 2002 without further rate relief (See "Power Supply Commitments", "Retail Rate Cases" and "Risk Factors" in this section).

Power supply expenses constituted 79.4, 75.4, and 67.7 percent of total operating expenses for the years 2000, 1999, and 1998, respectively. Power supply expenses increased by $30.2 million or 16.5 percent in 2000 and $62.2 million or 51.4 percent in 1999. The increase in power supply expenses from 1999 to 2000 resulted from the following:

* a $20.0 million increase from power purchased for resale, primarily under a power supply agreement discussed below, whereby we buy power from MS that is sufficient to serve pre-established load requirements at a pre-defined price;
* a $7.7 million increase in energy costs arising from a power supply arrangement with Hydro-Quebec, discussed below, whereby Hydro-Quebec has an option to purchase energy at prices that were below market replacement costs;
* the costs to serve increased retail sales of electricity of 2.8 percent in 2000 and higher unit power supply costs; and
* a $3.6 million increase in capacity costs associated with our long-term Hydro-Quebec power supply contract.

These amounts were partially offset by a reduction in 2000 of $9.7 million in losses accrued for the Hydro-Quebec power cost disallowance under past regulatory rulings. Results for 1999 reflected pretax charges of $2.2 million in disallowed Hydro-Quebec power costs, compared with the amortization during 2000 of accrued power expense of $7.5 million for 2000 that had been recorded in 1999. The power supply costs of Company-owned generation increased 74.8 percent or $4.2 million in 2000 due to purchases by MS under a power supply agreement discussed below and because units were dispatched for system reliability requirements due to the unavailability of certain transmission facilities. Power supply expenses increased by $62.2 million or 51.4 percent from 1998 to 1999. The increase in power supply expenses from 1998 to 1999 resulted from the following:

* a $57.0 million increase reflecting the power purchase and supply agreement discussed below, whereby we buy power from MS that is sufficient to serve pre-established load requirements at a pre-defined price;
* a $4.3 million increase in the capacity costs in 1999 associated with our long-term Hydro-Quebec power supply contract;
* an increase in the costs of short-term power following the deregulation of wholesale energy markets in New England, as well as an increase in our costs to serve increased local loads and to supply power to meet contractual obligations under the Company's December 1997 sell-back arrangement with Hydro-Quebec (net

cost approximately $5.4 million); and

* a $1.9 million increase in Vermont Yankee capacity costs.

These amounts were partially offset by a reduction of $2.3 million in losses accrued for the Hydro-Quebec power cost disallowance. Results for 1998 reflected pretax charges of $9.8 million in disallowed Hydro-Quebec power costs for both 1998 and 1999, compared with disallowed power costs of $7.5 million for 2000 recorded in 1999.

The power supply costs of Company-owned generation decreased 13.0 percent in 1999 due to the severe 1998 ice storm in New England that caused increased usage in that year of peak generation resources to replace power that was unavailable from Hydro-Quebec.

An Independent System Operator in New England ("ISO") replaced the New England Power Pool ("NEPOOL") effective May 1, 1999. The ISO works as a clearinghouse for purchasers and sellers of electricity in the new deregulated wholesale markets. Sellers place bids for the sale of their generation or purchased power resources and if demand is high enough the output from those resources is sold.

We must purchase electricity to meet customer demand during periods of high usage and to replace energy repurchased by Hydro-Quebec under an arrangement negotiated in 1997. Our costs to serve demand during periods of warmer than normal temperatures in summer months and to replace such energy repurchases by Hydro-Quebec rose substantially after the wholesale power markets became deregulated, which caused much greater volatility in spot prices for electricity. The cost of securing future power supplies has also risen substantially in tandem with higher summer power supply costs. The Company cannot predict the duration or the extent to which future prices will continue to trade above historical levels of cost. If the new markets continue to experience the volatility evident during 1999 and 2000, our earnings and cash flow could be adversely impacted by a material amount.

POWER CONTRACT COMMITMENTS- On February 11, 1999, we entered into a contract with MS as a result of our power requirements solicitation in 1998. A master power purchase and sales agreement ("PPSA") defines the general contract terms under which the parties may transact. The sales under the PPSA commenced on February 12, 1999 and will terminate after all obligations under each transaction entered into by MS and the Company has been fulfilled. The PPSA has been noticed to the VPSB and filed with the Federal Energy Regulatory Commission ("FERC"). In January 2001, the PPSA was modified and extended to December 31, 2003.

The PPSA provides us with a means of managing price risks associated with changing fossil fuel prices. On a daily basis, and at MS's discretion, we sell power to MS from either (i) all or part of our portfolio of power resources at predefined operating and pricing parameters or (ii) any power resources available to us, provided that sales of power from sources other than Company-owned generation comply with the predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements. MS is also responsible for scheduling supply resources. We remain responsible for resource performance and availability. MS provides no coverage against major unscheduled outages. The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. We estimate that the Company saved approximately $4.8 million during 2000 over what our energy costs would have been absent the PPSA due to our avoiding significant increases in 2000 fossil fuel prices.

During 1994, we negotiated an arrangement with Hydro-Quebec that reduced the cost under our 1987 contract with Hydro-Quebec over the November 1995 through October 1999 period (the "July 1994 Agreement").

As part of the July 1994 Agreement, we were obligated to purchase $4.0 million (in 1994 dollars) worth of research and development work from Hydro-Quebec over a four-year period (which has since been extended to 2001), and made a $6.5 million (in 1994 dollars) payment to Hydro-Quebec in 1995.

Hydro-Quebec retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2000 to 2015 period, if documented drought conditions exist in Qu bec.

During the first year of the July 1994 Agreement (the period from November 1995 through October 1996), the average cost per kilowatt-hour of Schedules B and C3 combined was cut from 6.4 to 4.2 cents per kilowatt-hour, a 34 percent (or $16 million) cost reduction. Over the period from November 1996 through December 2000 and accounting for the payments to Hydro-Quebec, the combined unit costs will be lowered from 6.5 to 5.9 cents per kilowatt-hour, reducing unit costs by 10 percent and saving $20.7 million in nominal terms.

Under a power supply arrangement executed in January 1996 ("9601"), we received payments from Hydro-Quebec of $3.0 million in 1996 and $1.1 million in 1997. Under 9601 we are required to shift up to 40 megawatts of deliveries to an alternate transmission path, and use the associated portion of the NEPOOL/Hydro-Quebec interconnection facilities to purchase power for the period from September 1996 through June 2001 at prices that vary based upon conditions in effect when the purchases are made. 9601 also provides for minimum payments by the Company to Hydro-Quebec for periods in which power is not purchased under the arrangement. 9601 allows Hydro-Quebec to curtail deliveries of energy should it need to use certain resources to supplement available supply. Hydro-Quebec did curtail deliveries in the fourth quarter of 2000. Although our level of future benefits will depend on various factors, including market prices and availability of energy from HQ, we estimate that 9601 has provided a benefit of approximately $3.0 million on a net present value basis through December 31, 2000.

Under a separate arrangement executed on December 5, 1997 ("9701"), Hydro-Quebec paid $8.0 million to the Company in 1997. In return for this payment, we provided Hydro-Quebec options for the purchase of power. Commencing April 1, 1998 and effective through the term of the 1987 Contract, which ends in 2015, Hydro-Quebec may purchase up to 52,500 MWh ("option A") on an annual basis, at the 1987 Contract energy prices, which are substantially below current market prices. The cumulative amount of energy that may be purchased under option A shall not exceed 950,000 MWh

Over the same period, Hydro-Quebec may exercise an option to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy price. Under option B, Hydro-Quebec may purchase no more than 200,000 MWh in any year. As of December 31, 2000, Hydro-Quebec had purchased or called to purchase 349,000 MWh under option B, including calls for January and February of 2001.

In 2000, Hydro-Quebec exercised option A and option B, calling for deliveries to third parties at a net cost to the Company of approximately $14.0 million (including the cost of January and February, 2001 calls, and the cost of related financial positions), which was due to higher energy replacement costs incurred by the Company. Approximately $6.6 million of the $14.0 million net 9701 costs were recovered in rates on an annual basis.

In 1999, Hydro-Quebec called for deliveries to third parties at a net cost of approximately $6.3 million. Hydro-Quebec's option to curtail energy deliveries pursuant to the July 1994 Agreement can be exercised in addition to these purchase options.

The VPSB, in the Settlement Order said, "The record does not demonstrate that any other New England utility foresaw the extent and degree of volatility that has developed in the New England wholesale power markets. Absent that volatility, the 97-01 Agreement would not have had adverse effects." In conjunction with the Settlement Order, Hydro-Quebec committed to the Department, that it would not call any energy under option B of 9701 during 2002.

In 1999, the Company and the other Vermont Joint Owners who are parties to the Hydro-Quebec contract initiated an arbitration against Hydro-Quebec, pursuant to the 1987 Contract terms, to determine whether Hydro-Quebec's suspension of deliveries of power to Vermont during and after the January 1998 ice storm evidenced a default by Hydro-Quebec under the terms of that contract. Hydro-Quebec maintains that the "force majeure" (superior or irreversible force) provision in the 1987 Contract applies, which could excuse its non-delivery of power under these circumstances. Arbitration of the dispute may lead to remedies having a material impact on our contractual obligation, including the possibility that the 1987 Contract be declared terminated or void. If arbitration results in a cash payment, it will first be applied to a regulatory asset of $4.7 million for arbitration litigation costs. The Settlement Order provides that the Company will not earn a return on these litigation costs, unless the case results in lower power supply costs for ratepayers. Hearings have concluded and a decision is expected in April 2001. If the contract is declared terminated or void, the Company would have to replace a substantial amount of its power needs at terms which could materially exceed the 1987 Contract price for 2001. The Company believes that it could contract replacement power at costs below the long term costs of the 1987 Contract.

OTHER OPERATING EXPENSES- Other operating expenses increased $0.1 million in 2000. The increase is primarily due to a $3.2 million charge for disallowed regulatory litigation costs, ordered by the VPSB as part of the Settlement Order. The increase was offset by a $3.3 million decrease in administrative and general expense caused by the Company's reorganization efforts that reduced the size of the workforce and lowered building occupancy costs.

Other operating expenses decreased $3.7 million or 17.4 percent in 1999. The decrease resulted from:

* a $1.9 million estimated loss in 1998 to recognize the cost of terminating the Company's corporate headquarters operating lease. The facilities were sold in April 1999;
* a $1.4 million reduction in administrative and general salaries related to a workforce reduction plan;
* the elimination in 1999 of a regulatory liability of $1.2 million relating to the Company's former corporate headquarters; and
* reductions in lease expense and facility carrying costs resulting from the disposal of the former headquarters.

These savings were partially offset by increased costs of approximately $1.8 million associated with the Company's reorganization.

TRANSMISSION EXPENSES-Transmission expenses increased $1.5 million or 14.0 percent in 2000 primarily due to congestion charges that reflect the lack of adequate transmission or generation capacity in certain locations within New England. These charges are allocated to all ISO New England members. The Company is unable to predict the magnitude or duration of future congestion charge allocation, but amounts could be material. Transmission expenses increased $1.4 million or 15.0 percent in 1999 due to costs associated with the creation of the ISO as the clearing house for power trades in New England and due to refunds in 1998 from Central Vermont Public Service Corp. and New England Power Company.

A FERC ruling in December 2000 required ISO New England to revise its installed capability ("ICAP") deficiency charge of $0.17 per kw month to $8.75 per kw month retroactive to August 1, 2000. On January 10, 2001, FERC stayed its order "to ensure that bills for past periods will not be assessed until the Commission has considered the pending requests for rehearing, which, if successful, would then require extensive refunds and surcharges." On March 6, 2001, FERC issued an Order on Rehearing in which it partly reversed itself on the ICAP charge. Although the Commission first concluded that a $8.75 charge is reasonable and that the charge would remain in place until the ISO supports an acceptable superseding proposal, the Commission then concluded that reinstating the $8.75 would have a large cost impact. As a result, the $0.17 per kW month charge was reinstated from August 1, 2000 until April 1, 2001. The Commission allowed the $8.75 charge to become effective on April 1, 2001 until the effective date of any superseding charge the Commission might accept. On March 16, 2001, an ISO New England participant filed a request for re-hearing the FERC's March 6, 2001 Order on Rehearing. The request asks for a reversal of the lowered ICAP charge for the period from August 1, 2000 until April 1, 2001. If the lowered ICAP charge is increased to $8.75 per kw month, then the Company would be required to pay ISO New England approximately $1.4 million. Management cannot determine the ultimate impact of the request at this time.

In 2000, FERC issued a separate order ("Order 2000") requiring all utilities to file plans for the formation and administration of regional transmission organizations ("RTO"). In January 2001, the Company and other Vermont transmission owning companies filed in compliance with Order 2000. The Vermont companies support the Petition for Declaratory Order by various New England transmission owning companies, with reservations. The Vermont companies' principal concerns relate to:

* whether a New England RTO ("NERTO") will include all non-Pool Transmission Facilities in the NERTO Tariff on a rolled in basis;
* whether Highgate and Phase I/Phase II transmission facilities will be included in the Tariff without a separate transmission levy;
* whether NERTO will continue the transition to a single regional transmission rate; and
* the percentage of equity that transmission owners may acquire in the new organization.

The Company is unable to estimate how these issues will be resolved, but the impact could be material.

MAINTENANCE EXPENSES-Maintenance expenses decreased $0.1 million or 1.4 percent in 2000 due to changes in scheduled maintenance. Maintenance expenses increased $1.5 million or 29.6 percent in 1999, reflecting increased expenditures on right-of-way maintenance programs.

DEPRECIATION AND AMORTIZATION- Depreciation and amortization expenses decreased $0.9 million or 5.5 percent in 2000 due to reductions in amortization of demand side management costs that were only partially offset by increased depreciation of utility plant in service. In 1999, depreciation and amortization were at similar levels compared with that of 1998.

INCOME TAXES-Income tax amounts decreased for 2000 due to an increase in the Company's taxable loss. Income taxes decreased for 1999 due to a decrease in taxable income.

OTHER INCOME- Other income decreased $0.7 million in 2000 due to a $0.6 million gain on the 1999 sale of GMER. Other income increased $1.9 million in 1999, due to the 1999 gain on the sale of the Company's remaining interest in GMER discussed previously under "Unregulated Businesses", and a $0.9 million write-off in 1998 for disallowed costs at our Searsburg wind project.

INTEREST CHARGES-Interest expense increased $0.1 million or 1.0 percent in 2000 due to increases in short-term debt and rising interest rates that were partially offset by reductions in long-term debt. Interest expense decreased $0.7 million or 8.7 percent in 1999, consistent with reductions in average long-term and short-term debt outstanding during the year.

DIVIDENDS ON PREFERRED STOCK- Dividends on preferred stock decreased $141,000, or 12.2 percent in 2000 due to repurchases of preferred stock. In 1999, the dividends on preferred stock also decreased $141,000 or 10.9 percent for the same reason.

ENVIRONMENTAL MATTERS

The electric industry typically uses or generates a range of potentially hazardous products in its operations. We must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with these requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site.

PINE STREET BARGE CANAL SITE-The Federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), commonly known as the "Superfund" law, generally imposes strict, joint and several liability, regardless of fault, for remediation of property contaminated with hazardous substances. We have previously been notified by the Environmental Protection Agency ("EPA") that we are one of several potentially responsible parties ("PRPs") for cleanup of the Pine Street Barge Canal site in Burlington, Vermont, where coal tar and other industrial materials were deposited.

In September 1999, we negotiated a final settlement with the United States, the State of Vermont (the "State"), and other parties to a Consent Decree that covers claims with respect to the site and implementation of the selected site cleanup remedy. In November 1999, the Consent Decree was filed in the federal district court. The Consent Decree addresses claims by the EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site.

As of December 31, 2000, our total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $23.5 million. This includes amounts not recovered in rates, amounts recovered in rates, and amounts for which rate recovery has been sought but which are presently awaiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals for a more expensive remedy at the site, litigation and related costs necessary to obtain settlements with insurers and other PRPs to provide amounts required to fund the clean up ("remediation costs"), and to address liability claims at the site. A smaller amount of past expenditures was for site-related response costs, including costs incurred pursuant to EPA and State orders that resulted in funding response activities at the site, and to reimbursing the EPA and the State for oversight and related response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be $12.4 million over the next 33 years. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We also have recorded an offsetting regulatory asset and we believe that it is probable that we will receive future revenues to recover these costs.

Through rate cases filed in 1991, 1993, 1994, and 1995, we sought and received recovery for ongoing expenses associated with the Pine Street Barge Canal site. While reserving the right to argue in the future about the appropriateness of full rate recovery of the site-related costs, the Company and the Department, and as applicable, other parties, reached agreements in these cases that the full amount of the site-related costs reflected in those rate cases should be recovered in rates.

We proposed in our rate filing made on June 16, 1997 recovery of an additional $3.0 million in such expenditures. In an Order in that case released March 2, 1998, the VPSB suspended the amortization of expenditures associated with the Pine Street Barge Canal site pending further proceedings. Although it did not eliminate the rate base deferral of these expenditures, or make any specific order in this regard, the VPSB indicated that it was inclined to agree with other parties in the case that the ultimate costs associated with the Pine Street Barge Canal site, taking into account recoveries from insurance carriers and other PRPs, should be shared between customers and shareholders of the Company. In response to our Motion for Reconsideration, the VPSB on June 8, 1998 stated its intent was "to reserve for a future docket issues pertaining to the sharing of remediation-related costs between the Company and its customers". The Settlement Order released January 23, 2001 did not change the status of Pine Street cost recovery.

CLEAN AIR ACT-Because we purchase most of our power supply from other utilities, we do not anticipate that we will incur any material direct cost increases as a result of the Federal Clean Air Act or proposals to make more stringent regulations under that Act. Furthermore, only one of our power supply purchase contracts, which expired in early 1998, related to a generating plant that was affected by Phase I of the acid rain provisions of this legislation, which went into effect January 1, 1995.

RATES

RETAIL RATE CASES- On March 2, 1998, the VPSB released its Order dated February 27, 1998 in the then pending rate case (the "1997 rate case"). The VPSB authorized us to increase our rates by 3.61 percent, which gave us increased annual revenues of $5.6 million. The VPSB Order denied us the right to charge customers $5.48 million of the annual costs for power purchased under our contract with Hydro-Quebec. The VPSB denied recovery of these costs for the following reasons:

* The VPSB claimed that we had acted imprudently by committing to the power contract with Hydro-Quebec in August 1991 (the imprudence disallowance); and
* To the extent that the costs of power to be purchased from Hydro-Quebec were higher than current estimates of market prices for power during the contract term, after accounting for the imprudence disallowance, the contract power was decreed not "used and useful".

We appealed the VPSB's ruling in the 1997 rate case to the Vermont Supreme Court.

On May 8, 1998, we filed a request with the VPSB to increase our retail rates by 12.93 percent due to higher power costs, the cost of the January 1998 ice storm, and investments in new plant and equipment (the "1998 rate case").

On November 18, 1998, by Memorandum of Understanding ("MOU"), the Company, the Department and IBM agreed to stay rate proceedings in the 1998 rate case until or after September 1, 1999, or such earlier date as the parties may later agree to or the VPSB may order. The agreement to suspend our 1998 rate case delayed the date of a final decision on the 1998 rate case to December 15, 1999, and we recognized an additional loss of $5.25 million in the last quarter of 1998 representing the effect of the continued disallowance of Hydro-Quebec costs through December 15, 1999. The MOU provided for a 5.5 percent temporary rate increase, to produce $8.9 million in annualized additional revenue, effective with service rendered December 15, 1998. An additional surcharge was permitted, without further VPSB order, in order to produce additional revenues necessary to provide the Company with the capacity to finance 1999 Pine Street Barge Canal site expenditures. The MOU was approved by the VPSB on December 11, 1998. The MOU did not provide for any specific disallowance of power costs under our purchase power contract with Hydro-Quebec. Issues respecting recovery of such power costs were preserved for future proceedings.

The stay and suspension of the 1998 rate case and the temporary rate levels agreed to in the MOU were designed to allow us to continue to provide adequate and efficient service to our customers while we sought mitigation of power supply costs.

On September 7 and December 17, 1999, the VPSB issued Orders approving two amendments to the MOU that the Company had entered into with the Department and IBM. The two amendments continued the stay of proceedings until September 1, 2000, with a final decision expected by December 31, 2000. The amendments maintained the other features of the original MOU, and the second amendment provided for a temporary rate increase of 3 percent, in addition to the previous temporary rate level, to become effective as of January 1, 2000. The Company reached a final settlement agreement with the Department in the 1998 rate case during November 2000. The final settlement agreement contains the following provisions:

* A rate increase of 3.42 percent above existing rates, beginning with bills

rendered January 23, 2001, and prior temporary rate increases became permanent;

* Rates set at levels that recover the Company's Hydro-Quebec VJO contract costs, effectively ending the regulatory disallowances experienced by the Company over the past three years;
* The Company agrees not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for additional rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;
* The Company agreed to write off approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaces short-term credit facilities with long-term debt or equity financing;
* Seasonal rates will be eliminated in April 2001, which is expected to generate approximately $6.0 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2001, 2002 and 2003;
* The Company agrees to consult extensively with the Department regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making; and
* The Company agrees to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the 1997 rate case.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions:

* The VPSB Order requires the Company and customers to share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share; and
* The second condition restricts Company investments in non-utility operations.

LIQUIDITY AND CAPITAL RESOURCES

CONSTRUCTION-Our capital requirements result from the need to construct facilities or to invest in programs to meet anticipated customer demand for electric service. Capital expenditures over the past three years and forecasted for 2001 are as follows:

	Generation	Transmission	Distribution	Conservation	Other*	Total
			(In thousands)			
Actual:						
1998. . .	$ 543	$ 751	$ 6,063	$ 1,244	$ 4,568	$13,169
1999. . .	210	144	5,930	1,943	9,039	17,266
2000. . .	2,195	931	7,169	**	3,955	14,250
Forecast:						

2001. . .	$ 2,830	$ 2,060	$ 8,540	**	$ 2,320	$15,750

* Other includes $6.1 million in 1999, $1.3 million in 2000, and $1.9 million in 2001 for the Pine Street Barge Canal Site.
**A state-wide Energy Efficiency Utility set up by the VPSB in 1999 manages all energy efficiency programs, receiving funds the Company bills to its customers as a separate charge.

DIVIDEND POLICY- The annual dividend rate was $0.55 per share at December 31, 2000.

The Settlement Order limits the dividend rate at its current level until short term credit facilities are replaced with long term debt or equity financing. Retained earnings at December 31, 2001 were approximately $0.5 million. The Company anticipates substantial improvement in retained earnings during 2001, beginning with the first quarter, and believes it will be able to maintain the current dividend rate. If retained earnings were eliminated, the Company would not be able to declare a dividend under its Restated Articles of Association.

FINANCING AND CAPITALIZATION-Internally-generated funds provided approximately 59 percent of requirements for 2000, 1999 and 1998 combined. Internally-generated funds, after payment of dividends, provide capital requirements for construction, sinking funds and other requirements. We anticipate that for 2001, internally generated funds will provide approximately 90 percent of total capital requirements for regulated operations.

At December 31, 2000, our capitalization consisted of 49.3 percent common equity, 43.8 percent long-term debt and 6.9 percent preferred equity.

On June 21, 2000, we renewed a $15.0 million revolving credit agreement with Fleet National Bank and Citizens Bank of Massachusetts (the "Fleet Agreement"). The Fleet Agreement is for a period of 364 days and will expire on June 20, 2001. At December 31, 2000, there was $0.5 million outstanding on the Fleet Agreement. The Fleet Agreement is secured by granting the banks a second priority mortgage, lien and security interest in the collateral pledged under the Company's first mortgage bond indenture.

On September 20, 2000, we established a $15.0 million revolving credit agreement with KeyBank National Association ("KeyBank"). The agreement will expire on September 19, 2001. Pursuant to a one year power supply option agreement between the Company and Energy East Corporation ("EE"), EE made a payment of $15.0 million to the Company. In exchange, the Company gave EE an option to purchase energy from certain wholly owned production facilities, for a period not to exceed 15 years, if the funds are not returned to EE upon request after September 2001. The Company was required to invest the funds provided by EE in a certificate of deposit at KeyBank pledged by the Company to secure the repayment of the Keybank revolving credit facility. At December 31, 2000, there was $15.0 million outstanding on the KeyBank line of credit.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2001. The Settlement Order will likely permit restoration of the Company's investment grade debt rating, allowing arrangement of such financing as the Company needs during 2001.

The credit ratings of the Company's securities are:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds . . .	BB+	Baa2	BBB
Unsecured medium term debt	BB-	--	--
Preferred stock.	B+	baa3	BB

On March 5, 2001, Moody's Investors Service upgraded the Company's first mortgage bond rating to Baa2 from Ba1, and upgraded the Company's preferred stock rating to baa3 from ba3. The rating action reflected Moody's earnings and cash flow expectations for the Company following the Settlement Order.

On August 25, 2000, Fitch (formerly Duff & Phelps) downgraded the credit ratings of the Company to below investment grade and maintained the ratings on Rating Watch-Negative. Since the Settlement Order, Fitch and Standard & Poor's have favorably changed their outlook relative to the ratings direction for the Company, moving us from Rating Watch-Negative and Credit Watch- Negative to Rating Watch-Positive and Credit Watch-Developing, respectively.

NUCLEAR DECOMMISSIONING-The staff of the SEC has questioned certain current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating units in financial statements. In response to these questions, the Financial Accounting Standards Board had agreed to review the accounting for closure and removal costs, including decommissioning. We do not believe that changes in such accounting, if required, would have an adverse effect on the results of operations due to our current and future ability to recover decommissioning costs through rates.

EFFECTS OF INFLATION-Financial statements are prepared in accordance with generally accepted accounting principles and report operating results in terms of historic costs. This accounting provides reasonable financial statements but does not always take inflation into consideration. As rate recovery is based on these historical costs and known and measurable changes, the Company is able to receive some rate relief for inflation. It does not receive immediate rate recovery relating to fixed costs associated with Company assets. Such fixed costs are recovered based on historic figures. Any effects of inflation on plant costs are generally offset by the fact that these assets are financed through long-term debt.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

GREEN MOUNTAIN POWER CORPORATION
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share data)	For the Years Ended Decemb	
	2000	1999
OPERATING REVENUES	$277,326	$251,0
OPERATING EXPENSES		
Power Supply		
Vermont Yankee Nuclear Power Corporation	34,813	34,9
Company-owned generation	9,756	5,5
Purchases from others	168,947	142,6
Other operating	17,644	17,5
Transmission	12,258	10,8
Maintenance	6,633	6,7
Depreciation and amortization	15,304	16,1
Taxes other than income	7,402	7,2
Income taxes	(691)	1,2

Total operating expenses	272,066	243,1
OPERATING INCOME	5,260	7,9
OTHER INCOME		
Equity in earnings of affiliates and non-utility operations	2,495	2,9
Allowance for equity funds used during construction	284	1
Other income (deductions), net	(73)	4
Total other income	2,706	3,4
INCOME BEFORE INTEREST CHARGES	7,966	11,3
INTEREST CHARGES		
Long-term debt	6,499	6,7
Other	986	5
Allowance for borrowed funds used during construction	(228)	(
Total interest charges	7,257	7,1
INCOME (LOSS) BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS	709	4,2
Dividends on preferred stock	1,014	1,1
INCOME (LOSS) FROM CONTINUING OPERATIONS	(305)	3,0
Net loss from discontinued segment operations, net of applicable income taxes.	-	(6
Loss on disposal, including provisions for operating losses during phaseout period, net of applicable income taxes	(6,549)	(6,6
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (6,854)	$ (4,2
COMMON STOCK DATA		
Basic and diluted earnings (loss) per share from discontinued operations	$ (1.19)	$ (1.
Basic and diluted earnings (loss) per share from continuing operations	(0.06)	0.
Basic and diluted earnings (loss) per share	$ (1.25)	$ (0.
Cash dividends declared per share	$ 0.55	$ 0.
Weighted average shares outstanding	5,491	5,3
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS		
Balance - beginning of period	$ 10,344	$ 17,5
Net Income (loss)	(5,840)	(3,0
	4,504	14,4
Cash dividends-redeemable cumulative preferred stock	1,014	1,1
Cash dividends-common stock	2,997	2,9
	4,011	4,1
Balance - end of period	$ 493	$ 10,3

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	FOR THE YEARS ENDED DECEMBER 31,		
	2000	1999	1998
OPERATING ACTIVITIES:	(In thousands)		
Net Loss	$ (5,840)	$(3,063)	($2,877)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation and amortization	15,304	16,187	16,059
Dividends from associated companies less equity income	(26)	169	812
Allowance for funds used during construction	(512)	(224)	(235)
Amortization of purchased power costs	5,575	5,725	6,405
Deferred income taxes	443	1,812	(112)
Loss on discontinued segment operations	6,549	6,676	-
Deferred purchased power costs	(6,692)	(6,590)	(7,830)
Accrued purchase power contract option call	8,276	-	-
Deferred arbitration costs	(3,184)	(1,684)	-
Amortization of investment tax credits	(282)	(282)	(282)
Provision for chargeoff of deferred regulatory asset	3,229	-	0
Environmental and conservation expenditures	(2,073)	(8,048)	1,177
Changes in:			
Accounts receivable	(3,862)	474	(1,611)
Accrued utility revenues	(125)	(358)	(105)
Fuel, materials and supplies	(766)	(150)	122
Prepayments and other current assets	(165)	4,009	(983)
Accounts payable	3,004	665	(1,893)
Accrued income taxes payable and receivable	(372)	(1,611)	(2,473)
Other current liabilities	(7,341)	1,722	3,229
Other	(180)	(324)	536
Net cash provided by continuing operations	10,959	15,105	9,939
Net change in discontinued segment	245	(138)	-
Net cash provided by operating activities	11,204	14,967	9,939
INVESTING ACTIVITIES:			
Construction expenditures	(13,853)	(9,174)	(10,900)
Proceeds from sale of subsdiaries	6,000	-	11,500
Investment in nonutility property	(187)	(190)	(1,442)
Net cash used in investing activities	(8,040)	(9,364)	(842)
FINANCING ACTIVITIES:			
Issuance of common stock	1,250	1,054	1,587
Investment in certificate of deposit, pledged for revolver.	(15,437)	-	-
Power supply option obligation	15,419	-	-
Short-term debt, net	7,600	900	4,384
Cash dividends	(4,011)	(4,101)	(6,332)
Reduction in preferred stock	(1,640)	(1,650)	(1,650)
Reduction in long-term debt	(6,700)	(1,700)	(6,767)
Net cash used in financing activities	(3,519)	(5,497)	(8,778)

Net increase(decrease) in cash and cash equivalents	(355)	106	319
Cash and cash equivalents at beginning of period.	696	590	271
Cash and cash equivalents at end of period.	$ 341	$ 696	$ 590
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid year-to-date for:			
Interest (net of amounts capitalized)	$ 7,185	$ 7,034	$ 7,857
Income taxes, net	1,191	997	2,285

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

(In thousands)	AT DECEMBER 31, 2000	1999
ASSETS		
UTILITY PLANT		
Utility plant, at original cost.	$291,107	$283,917
Less accumulated depreciation.	110,273	102,854
Net utility plant.	180,834	181,063
Property under capital lease	6,449	7,038
Construction work in progress.	7,389	4,795
Total utility plant, net	194,672	192,896
OTHER INVESTMENTS		
Associated companies, at equity.	14,373	14,545
Other investments.	6,357	6,120
Total other investments.	20,730	20,665
CURRENT ASSETS		
Cash and cash equivalents.	341	656
Certficate of deposit, pledged as collateral .	15,437	-
Accounts receivable, customers and others, less allowance for doubtful accounts of $463, and 398	22,365	18,503
Accrued utility revenues	7,093	6,969
Fuel, materials and supplies, at average cost.	4,056	3,290
Prepayments.	2,525	2,197
Income tax receivable.	1,613	1,241
Other.	222	382
Total current assets	53,652	33,238

DEFERRED CHARGES		
Demand side management programs.	6,358	7,640
Purchased power costs.	11,789	7,435
Pine Street Barge Canal.	12,370	8,700
Other.	15,519	19,521
Total deferred charges	46,036	43,296
NON-UTILITY		
Cash and cash equivalents.	-	40
Other current assets	8	8
Property and equipment	252	253
Business segment held for disposal	-	9,477
Other assets	1,258	1,321
Total non-utility assets	1,518	11,099
TOTAL ASSETS	$316,608	$301,194

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	AT DECEMBER 31,	
	2000	1999
(In thousands except share data)		
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock equity		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,582,552, and 5,425,571).	$ 18,608	$ 18,085
Additional paid-in capital	73,321	72,594
Retained earnings.	493	10,344
Treasury stock, at cost (15,856 shares).	(378)	(378)
Total common stock equity.	92,044	100,645
Redeemable cumulative preferred stock.	12,560	12,795
Long-term debt, less current maturities.	72,100	81,800
Total capitalization	176,704	195,240
CAPITAL LEASE OBLIGATION	6,449	7,038

CURRENT LIABILITIES		
Current maturities of preferred stock.	235	1,640
Current maturities of long-term debt	9,700	6,700
Short-term debt.	15,500	7,900
Accounts payable, trade and accrued liabilities.	7,755	6,684
Accounts payable to associated companies	8,510	6,577
Dividends declared	229	285
Customer deposits.	696	361
Accrued purchased power option call.	8,276	-
Interest accrued	1,150	1,169
Power supply option obligation	15,419	-
Other.	874	8,475
Total current liabilities.	68,344	39,791
DEFERRED CREDITS		
Accumulated deferred income taxes.	25,644	25,201
Unamortized investment tax credits	3,695	3,978
Pine Street Barge Canal site cleanup	11,554	8,815
Other.	20,901	21,131
Total deferred credits	61,794	59,125
COMMITMENTS AND CONTINGENCIES		
NON-UTILITY		
Liabilities of discontinued segment, net	3,317	-
Total non-utility liabilities.	3,317	-
TOTAL CAPITALIZATION AND LIABILITIES	$316,608	$301,194

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

CONSOLIDATED CAPITALIZATION DATA
GREEN MOUNTAIN POWER CORPORATION At December 31,

		SHARES ISSUED AND OUTSTANDING			
	AUTHORIZED	2000	1999	2000	1999
(In thousands)					
CAPITAL STOCK					
Common Stock, $3.33 1/3 par value.	10,000,000	5,582,552	5,425,571	18,608	$18,085

AUTHORIZED	ISSUED	OUTSTANDING 2000	1999	2000	1999	
Shares	(In thousands)					
REDEEMABLE CUMULATIVE PREFERRED STOCK, $100 PAR VALUE						
4.75%, Class B, redeemable at $101 per share	15,000	15,000	1,450	1,800	145	$
7%, Class C, redeemable at $101 per share	15,000	15,000	3,300	3,750	330	
9.375%, Class D, Series 1, redeemable at $101 per share . .	40,000	40,000	3,200	4,800	320	
8.625%, Class D, Series 3, redeemable at $100916 per share.	70,000	70,000	0	14,000	0	1,
7.32%, Class E, Series 1	200,000	120,000	120,000	120,000	12,000	12,
TOTAL PREFERRED STOCK.				$	12,795	$ 14

(In thousands)	2000	1999
LONG-TERM DEBT		
FIRST MORTGAGE BONDS		
5.71% Series due 2000	$ -	$ 5,000
6.21% Series due 2001	8,000	8,000
6.29% Series due 2002	8,000	8,000
6.41% Series due 2003	8,000	8,000
10.0% Series due 2004 - Cash sinking fund, $1,700,000 annually.	6,800	8,500
7.05% Series due 2006	4,000	4,000
7.18% Series due 2006	10,000	10,000
6.7% Series due 2018.	15,000	15,000
9.64% Series due 2020	9,000	9,000
8.65% Series due 2022 - Cash sinking fund, commences 2012 . . .	13,000	13,000
Total Long-term Debt Outstanding.	81,800	88,500
Less Current Maturities (due within one year)	9,700	6,700
TOTAL LONG-TERM DEBT, NET	$72,100	$81,800

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

Notes to Consolidated Financial Statements

A. SIGNIFICANT ACCOUNTING POLICIES

1. Organization and Basis of Presentation. Green Mountain Power Corporation (the Company) is an investor-owned electric services company located in Vermont that serves approximately one-quarter of Vermont's population. The most significant portion of the Company's net income is generated from its regulated electric utility operation, which purchases and generates electric power and distributes it to approximately 86,000 retail and wholesale customers. At December 31, 2000, the Company's primary subsidiary investment was Mountain Energy, Inc. ("MEI"), which had invested in energy generation, energy efficiency and wastewater treatment projects across the United States. In 1999, the Company decided to sell or dispose of the assets of MEI, and report its results as income (loss) from operations of a discontinued segment. MEI changed its name to Northern Water Resources, Inc. ("NWR") in January 2001. In 1998, the Company sold the assets of its wholly owned subsidiary, Green Mountain Propane Gas Company ("GMPG"). The Company's remaining wholly-owned subsidiaries, which are not regulated by the Vermont Public Service Board ("VPSB" or "the Board"), are Green Mountain Resources, Inc. ("GMRI"), which sold its remaining interest in Green Mountain Energy Resources in 1999 and is currently inactive, and GMP Real Estate Corporation. The results of these subsidiaries, excluding MEI, and the Company's unregulated rental water heater program are included in earnings of affiliates and non-utility operations in the Other Income section of the Consolidated Statements of Income. Summarized financial information for these subsidiaries is as follows:

(In thousands)	For the years ended December 31, 2000	1999	1998
Revenue. . . .	$1,034	$1,286	$2,876
Expense. . . .	495	184	2,857
Net Income . .	$ 539	$1,102	$ 19

The Company carries its investments in various associated companies, Vermont Yankee Nuclear Power Corporation ("Vermont Yankee"), Vermont Electric Power Company, Inc. ("VELCO"), New England Hydro-Transmission Corporation, and New England Hydro-Transmission Electric Company using the equity method of accounting. The Company's share of the net earnings or losses of these companies is also included in the Other Income section of the Consolidated Statements of Income. See Note B and Note L for additional information.

2. Regulatory Accounting. The Company's utility operations, including accounting records, rates, operations and certain other practices of its electric utility business, are subject to the regulatory authority of the Federal Energy Regulatory Commission (FERC) and the VPSB.

The accompanying consolidated financial statements conform to generally accepted accounting principles applicable to rate-regulated enterprises in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71 ("SFAS 71"), Accounting for Certain Types of Regulation. Under

SFAS 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. Conditions that could give rise to the discontinuance of SFAS 71 include (1) increasing competition that restricts the Company's ability to establish prices to recover specific costs, and (2) a change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. In the event that the Company no longer meets the criteria under SFAS 71, the Company would be required to write off related regulatory assets and liabilities. The Company continues to believe, based on current regulatory circumstances, that the use of regulatory accounting under SFAS 71 remains appropriate and that its regulatory assets are probable of recovery. Regulatory entities that influence the Company include the VPSB, the Vermont Department of Public Service ("DPS" or the "Department"), and FERC, among other federal, state and local regulatory agencies.

3. Impairment. The Company is required to evaluate long-lived assets, including regulatory assets, for potential impairment. Assets that are no longer probable of recovery through future revenues would be revalued based upon future cash flows. Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. As of December 31, 2000, based upon the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss need be recorded. Competitive influences or regulatory developments may impact this status in the future.

4. Utility Plant. The cost of plant additions includes all construction-related direct labor and materials, as well as indirect construction costs, including the cost of money ("Allowance for Funds Used During Construction" or "AFUDC"). As part of the rate agreement with the DPS, the Company discontinued recording AFUDC on construction work in progress in January 2001. The costs of renewals and improvements of property units are capitalized. The costs of maintenance, repairs and replacements of minor property items are charged to maintenance expense. The costs of units of property removed from service, net of removal costs and salvage, are charged to accumulated depreciation over the estimated service life of the units.

5. Depreciation. The Company provides for depreciation using the straight-line method based on the cost and estimated remaining service life of the depreciable property outstanding at the beginning of the year and adjusted for salvage value and cost of removal of the property.

The annual depreciation provision was approximately 3.5 percent of total depreciable property at the beginning of 2000, 3.3 percent at the beginning of 1999 and 3.4 percent at the beginning of 1998.

6. Cash and Cash equivalents. Cash and cash equivalents include short-term investments with maturities less than ninety days.

7. Operating Revenues. Operating revenues consist principally of sales of electric energy. The Company accrues utility revenues, based on estimates of electric service rendered and not billed at the end of an accounting period, in order to match revenues with related costs.

8. Deferred Charges. In a manner consistent with authorized or expected ratemaking treatment, the Company defers and amortizes certain replacement power, maintenance and other costs associated with the Vermont Yankee Nuclear Power Corporation's generation plant. In addition, the Company accrues and amortizes other replacement power expenses to reflect more accurately its cost of service to better match revenues and expenses consistent with regulatory treatment. The Company also defers and amortizes costs associated with its investment in the demand side management program.

Other deferred charges totaled $15.5 million and $19.5 million at December 31, 2000 and 1999 respectively, consisting of regulatory deferrals of storm damages, rights-of-way maintenance, other employee benefits, preliminary survey and investigation charges, transmission interconnection charges and various other projects and deferrals.

9. Earnings Per Share. Earnings per share are based on the weighted average number of common and common stock equivalent shares outstanding during each year. The Company established an stock incentive plan for all employees during the year ended December 31, 2000, and granted 334,900 options exercisable over vesting schedules of between one and four years. Since the Company experienced a net loss in the year 2000, basic and diluted earnings per share are the same.

10. Major Customers. The Company had one major retail customer, IBM, metered at two locations, that accounted for 11.2 percent, 11.8 percent, and 14.7 percent of total operating revenues, and 16.5 percent, 16.4 percent and 17.1 percent of the Company's retail operating revenues in 2000, 1999 and 1998, respectively. IBM's percent of total revenues in 2000 decreased due to an increase in total operating revenues as a result of sales for resale pursuant to the Morgan Stanley Capital Group, Inc. ("MS") agreement. See Note K for further information regarding the MS agreement.

11. Fair Value of Financial Instruments. The present value of the first mortgage bonds and preferred stock outstanding, if refinanced using prevailing market rates of interest, would decrease from the balances outstanding at December 31, 2000 by approximately 4.6 percent. In the event of such a refinancing, there would be no gain or loss, because under established regulatory precedent, any such difference would be reflected in rates and have no effect upon income.

12. Deferred Credits. At December 31, 2000, the Company had other deferred credits and long-term liabilities of $32.4 million, consisting of reserves for damage claims and environmental liabilities, and accruals for employee benefits compared with a balance of $30.4 million at December 31, 1999.

13. Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires the use of estimates and assumptions that affect assets and liabilities, the disclosure of contingent assets and liabilities, and revenues and expenses. Actual results could differ from those estimates.

14. Reclassification. Certain items on the prior year's consolidated financial statements have been reclassified to be consistent with the current year presentation.

15. New Accounting Standards. In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, amended by Statement No. 137, Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133 and Statement 138, Accounting for Certain Derivatives and Certain Hedging Activities (collectively "SFAS 133").

SFAS 133 establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or a liability and measured at their fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133 is effective for the Company beginning the first quarter of 2001 and must be applied to derivative instruments and embedded derivatives that were issued, acquired, or substantively modified on or after January 1, 1998 or January 1, 1999 (as elected by the Company).

We have not yet quantified all effects of adopting SFAS 133 on our financial statements. However, a discussion of the Company's material derivative obligations follows and includes estimates of the fair values of each derivative. The Company has sought an accounting order from the VPSB to determine regulatory treatment for recording derivatives at fair market value. We believe it is probable that the VPSB will order that the Company defer recognition of any earnings or other comprehensive income effect relating to future periods caused by application of SFAS 133. We expect the VPSB to issue the accounting order prior to reporting our first quarter results, and consequently do not anticipate SFAS 133 to cause earnings volatility.

If the VPSB issues such an order, and if a derivative instrument is terminated early because it is probable that a transaction or forecasted transaction will not occur, any gain or loss will be recognized immediately. If such derivative is terminated for other economic reasons, any gain or loss as of the termination date is deferred and recorded when the associated transaction or forecasted transaction affects earnings. For derivatives held to maturity, the income statement impact of derivatives would be recognized in the period that the derivative is sold or matures.

If the VPSB does not issue an order or issues an order that does not require deferral of the earnings impacts resulting from application of SFAS 133, management estimates that adoption would result in earnings/loss recognition equivalent to the fair values of the respective assets/liabilities disclosed below, as adjusted by future changes in estimates.

The Company has a contract with MS used to hedge against increases in fossil fuel prices. MS purchases the majority of Company power supply resources at index (fossil fuel resources) or specified (i.e. contracted resources) prices and then sells to us at a fixed rate to serve pre-established load requirements. This contract allows management to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The MS contract is a derivative under SFAS 133 and is effective through December 31, 2003. Management's current estimate of the fair value of the future net benefit (cost) of this arrangement is between $7.2 million and ($14.0) million.

We also sometimes use future contracts to hedge forecasted wholesale sales of electric power, including material sales commitments as discussed under Note K. We currently have an arrangement with Hydro-Quebec that grants them an option to call power at prices below current and estimated future market rates. This arrangement is a derivative and is effective through 2016. Management's current estimate of the fair value of the future net cost for this arrangement is between $24.5 and $29.5 million.

B. INVESTMENTS IN ASSOCIATED COMPANIES

The Company accounts for investments in the following associated companies by the equity method:

(IN THOUSANDS)	PERCENT OWNERSHIP AT DECEMBER 31,2000	INVESTMENT IN EQUITY AT DECEMBER 31, 2000	1999
VELCO-common.	29.50%	$ 1,916	$1,839
VELCO-preferred	30.00%	540	690
Total VELCO	.	2,456	2,529

Vermont Yankee- Common.	17.88%	9,713	9,641
New England Hydro Transmission-Common . .	3.18%	827	911
New England Hydro Transmission Electric- Common.	3.18%	1,377	1,464
Total investment in associated companies.		$14,373	$14,545

Undistributed earnings in associated companies totaled $908,000 at December 31, 2000.

VELCO. VELCO is a corporation engaged in the transmission of electric power within the State of Vermont. VELCO has entered into transmission agreements with the State of Vermont and other electric utilities, and under these agreements, VELCO bills all costs, including interest on debt and a fixed return on equity, to the State and others using VELCO's transmission system. The Company's purchases of transmission services from VELCO were $9.7 million, $7.9 million, and $7.1 million for the years 2000, 1999 and 1998, respectively. Pursuant to VELCO's Amended Articles of Association, the Company is entitled to approximately 30 percent of the dividends distributed by VELCO. The Company has recorded its equity in earnings on this basis and also is obligated to provide its proportionate share of the equity capital requirements of VELCO through continuing purchases of its common stock, if necessary.

Summarized financial information for VELCO is as follows:

	AT AND FOR THE YEARS ENDED DECEMBER 31,		
	2000	1999	1998
	(In thousands)		
Company's equity in net income.	$ 395	$ 357	$ 338
Total assets.	$82,123	$67,294	$67,658
Less:			
Liabilities and long-term debt.	73,874	58,731	58,690
Net assets.	$ 8,249	$ 8,563	$ 8,968
Company's equity in net assets.	$ 2,456	$ 2,529	$ 2,657

Vermont Yankee. The Company is responsible for approximately 17.9 percent of Vermont Yankee's expenses of operations, including costs of equity capital and estimated costs of decommissioning, and is entitled to a similar share of the power output of the nuclear plant, which has a net capacity of 531 megawatts. Vermont Yankee's current estimate of decommissioning costs is approximately $430 million, using the 1993 FERC approved escalation rate of 5.4%, of which $247 million has been funded. At December 31, 2000, the Company's portion of the net unfunded liability was $33 million, which it expects will be recovered through rates over Vermont Yankee's remaining operating life. As a sponsor of Vermont Yankee, the Company also is obligated to provide 20 percent of capital requirements not obtained by outside sources. During 2000, the Company incurred

$27.8 million in Vermont Yankee annual capacity charges, which included $2.4 million for interest charges. The Company's share of Vermont Yankee's long-term debt at December 31, 2000 was $17.1 million.

On October 15, 1999, the owners of Vermont Yankee Nuclear Power Corporation accepted a bid from AmerGen Energy Company for the Vermont Yankee generating plant, intending to complete the sale before December 2000. AmerGen and the DPS then negotiated a revised offer in November 2000, which was subsequently dismissed as insufficient by the VPSB in February 2001. Entergy Nuclear Inc. has also made an offer, and two other companies have indicated they would participate in an auction, if held. The plant is likely to be sold at auction, the terms and conditions of which are unknown at this time.

The Price-Anderson Act currently limits public liability from a single incident at a nuclear power plant to $9.5 billion. Any damages beyond $9.5 billion are indemnified under the Price-Anderson Act, but subject to congressional approval. The first $200 million of liability coverage is the maximum provided by private insurance. The Secondary Financial Protection Program is a retrospective insurance plan providing additional coverage up to $9.3 billion per incident by assessing each of the 106 reactor units that are currently subject to the Program in the United States a total of $88.1 million, limited to a maximum assessment of $10 million per incident per nuclear unit in any one year. The maximum assessment is adjusted at least every five years to reflect inflationary changes.

The above insurance covers all workers employed at nuclear facilities for bodily injury claims. Vermont Yankee retains a potential obligation for retrospective adjustments due to past operations of several smaller facilities that did not join the above insurance program. These exposures will cease to exist no later than December 31, 2007. Vermont Yankee's maximum retrospective obligation remains at $3.1 million. Insurance has been purchased from Nuclear Electric Insurance Limited ("NEIL") to cover the costs of property damage, decontamination or premature decommissioning resulting from a nuclear incident. All companies insured with NEIL are subject to retroactive assessments if losses exceed the accumulated funds available. The maximum potential assessment against Vermont Yankee with respect to NEIL losses arising during the current policy year is $8.1 million. Vermont Yankee's liability for the retrospective premium adjustment for any policy year ceases six years after the end of that policy year unless prior demand has been made.

Summarized financial information for Vermont Yankee is as follows:

At and for the years ended December 31,

(In thousands)	2000	1999	1998
Earnings:			
Operating revenues	$178,294	$208,812	$195,249
Net income applicable to common stock.	6,583	6,471	7,125
Company's equity in net income	$ 1,177	$ 1,165	$ 1,267
Total assets	$706,984	$685,292	$635,874
Less:			
Liabilities and long-term debt	652,663	631,365	581,231
Net Assets	$ 54,321	$ 53,927	$ 54,643
Company's equity in net assets	$ 9,713	$ 9,641	$ 9,759

C. COMMON STOCK EQUITY

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 456,554 shares were reserved and unissued at December 31, 2000. The Company also funds an Employee Savings and Investment Plan ("ESIP"). At December 31, 2000, there were 174,263 shares reserved and unissued under the ESIP.

During 2000, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established a stock incentive plan. Under this plan, options for up to 500,000 shares may be granted to any employee, officer, consultant, contractor or Director providing services to the Company. Outstanding options become exercisable at between one and four years after the grant date and remain exercisable until 10 years from the grant date.

As permitted by Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation,"("SFAS 123") the Company has elected to follow Accounting Principles Board Opinion No. 25 ("APB 25") "Accounting for Stock Issued to Employees", and related interpretations in accounting for its employee stock options. Under APB 25, because the exercise price equals the market price of the underlying stock on the date of grant, no compensation expense is recorded.

Disclosure of proforma information regarding net income and earnings per share is required by SFAS 123. The information presented below has been determined as if the Company accounted for its employee stock options under the fair value method of that statement. The fair values of the options granted in 2000 are $2.03 per share. They were estimated at the grant date using the Black-Scholes option-pricing model with the following weighted average assumptions:

Assumptions

	2000
Risk-free interest rate .	6.05%
Expected life in years. .	7
Expected stock volatility	30.58%
Dividend yield.	4.50%

Proforma net earnings loss per share and a summary of options outstanding are as follows:

Proforma net income (loss)

	2000
Net income (loss)per share	
As reported.	$(1.25)
Pro-forma.	$(1.25)
Diluted earnings per share	
As reported.	$(1.25)
Pro-forma.	$(1.25)

	Weighted Average Options	Price
Outstanding at 12/31/99	-	$ -
Granted	334,900	7.90
Exercised	-	-
Forfeited	3,400	7.90
Outstanding at 12/31/00	331,500	$ 7.90

No options granted in 2000 became exercisable in 2000. The pro-forma amounts may not be representative of future disclosures since the estimated fair value of stock options is amortized to expense over the vesting period and additional options may be granted in future years. For 2000, the number of total shares after giving effect to anti-dilutive common stock equivalents does not change.

The following summarizes the plan's stock options outstanding:

	Weighted average Plan year	Outstanding exercise price	Remaining options at 12/31/00	Contractual Life
2000	$ 7.90	331,500	9.6 years	

During 2000, the Compensation Program for Officers and Certain Key Management personnel, that authorized payment of cash, restricted and unrestricted stock grants based on corporate performance was replaced with the stock incentive plan discussed above. Approximately 2000 restricted shares, issued during 1996 and 1997, remained unvested under this program.

Changes in common stock equity for the years ended December 31, 1998, 1999 and 200

	COMMON STOCK		PAID-IN	RETAINED	TREA
	SHARES	AMOUNT	CAPITAL	EARNINGS	SHAR

(Dollars in thousands)

BALANCE, DECEMBER 31, 1997	5,195,432	$ 17,318	$ 70,720	$ 26,717	15,8
Common Stock Issuance:					
DRIP	88,004	293	928	-	
ESIP	36,391	121	427	-	
Compensation Program:. .	-				
Restricted Shares . .	(6,531)	(21)	(161)	-	
Net Loss	-	-	-	(2,877)	
Cash Dividends	-				
Common Stock	-	-	-	(5,036)	
Preferred Stock:					
$4.75 per share.	-	-	-	(12)	
$7.00 per share.	-	-	-	(32)	
$9.375 per share	-	-	-	(72)	
$8.625 per share	-	-	-	(302)	
$7.32 per share.	-	-	-	(878)	
BALANCE, DECEMBER 31, 1998	5,313,296	$ 17,711	$ 71,914	$ 17,508	15,8
Common Stock Issuance:					
DRIP	67,525	225	418	-	
ESIP	48,277	161	345	-	
Compensation Program:					
Restricted Shares . .	(3,527)	(12)	(83)	-	
Net Loss	-	-	-	(3,063)	
Cash Dividends					
Common Stock	-	-	-	(2,946)	
Preferred Stock:					
$4.75 per share.	-	-	-	(10)	
$7.00 per share.	-	-	-	(29)	
$9.375 per share	-	-	-	(57)	
$8.625 per share	-	-	-	(181)	
$7.32 per share.	-	-	-	(878)	
BALANCE, DECEMBER 31, 1999	5,425,571	$ 18,085	$ 72,594	$ 10,344	15,8
Common Stock Issuance:					
DRIP	73,859	246	363	-	
ESIP	83,931	280	401	-	
Compensation Program:					
Restricted Shares . .	(809)	(3)	(37)	-	
Net Loss	-	-	-	(5,840)	
Cash Dividends					
Common Stock	-	-	-	(2,997)	
Preferred Stock:					
$4.75 per share.	-	-	-	(8)	
$7.00 per share.	-	-	-	(26)	
$9.375 per share	-	-	-	(42)	
$8.625 per share	-	-	-	(60)	
$7.32 per share.	-	-	-	(878)	
BALANCE, DECEMBER 31, 2000	5,582,552	$ 18,608	$ 73,321	$ 493	15,8

Dividend Restrictions. Certain restrictions on the payment of cash dividends on common stock are contained in the Company's indentures relating to long-term debt and in the Restated Articles of Association. Under the most restrictive of such provisions, approximately $0.5 million of retained earnings were free of restrictions at December 31, 2000.

The properties of the Company include several hydroelectric projects licensed under the Federal Power Act, with license expiration dates ranging from 2001 to 2025. At December 31, 2000, $161,000 of retained deficit had been appropriated as excess earnings on hydroelectric projects as required by Section 10(d) of the Federal Power Act.

D. PREFERRED STOCK

The holders of the preferred stock are entitled to specific voting rights with respect to certain types of corporate actions. They are also entitled to elect the smallest number of directors necessary to constitute a majority of the Board of Directors in the event of preferred stock dividend arrearages equivalent to or exceeding four quarterly dividends. Similarly, the holders of the preferred stock are entitled to elect two directors in the event of default in any purchase or sinking fund requirements provided for any class of preferred stock.

Certain classes of preferred stock are subject to annual purchase or sinking fund requirements. The sinking fund requirements are mandatory. The purchase fund requirements are mandatory, but holders may elect not to accept the purchase offer. The redemption or purchase price to satisfy these requirements may not exceed $100 per share plus accrued dividends. All shares redeemed or purchased in connection with these requirements must be canceled and may not be reissued. The annual purchase and sinking fund requirements for the year 2001 for certain classes of preferred stock are as follows:

	Class	Purchase and Sinking Fund Due dates	Shares to Retire
4.750%	Class B	December 1	300
7.000%	Class C	December 1	450
9.375%	Class D, Series 1	December 1	1,600

Under the Restated Articles of Association relating to Redeemable Cumulative Preferred Stock, the annual aggregate amount of purchase and sinking fund requirements for the next five years are $235,000 each for 2001 and 2002, $75,000 each for 2003 and 2004, $70,000 for 2005 and $105,000 thereafter.

Certain classes of preferred stock are redeemable at the option of the Company or, in the case of voluntary liquidation, at various prices on various dates. The prices include the par value of the issue plus any accrued dividends and a redemption premium. The redemption premium for Class B, C and D, Series 1, is $1.00 per share.

E. LONG-TERM DEBT

Substantially all of the property and franchises of the Company are subject to the lien of the indenture under which first mortgage bonds have been issued. The weighted average rate on long term borrowings outstanding was 7.6 percent and 7.5 percent at December 31, 2000 and 1999, respectively. The annual sinking fund requirements (excluding amounts that may be satisfied by property additions) and long-term debt maturities for the next five years are:

Sinking Fund	Maturities	Total

(In thousands)

2001	$ 1,700	$ 8,000	$9,700
2002	1,700	8,000	9,700
2003	1,700	8,000	9,700
2004	1,700		1,700
2005	1,700		1,700

F. SHORT-TERM DEBT

The Company has a revolving credit agreement with Fleet Financial Services and Citizens Bank of Massachusetts (the "Fleet agreement") in the amount of $15.0 million, with borrowings outstanding of $500,000 and $7.9 million at December 31, 2000, and 1999 respectively. The 364-day Fleet agreement expires June 2001. The weighted average interest rate on short-term borrowings outstanding at December 31, 2000 and December 31, 1999 was 9.5 percent and 9.0 percent, respectively. There was no non-utility short-term debt outstanding at December 31, 2000.

The Fleet agreement requires the Company to certify on a quarterly basis that it has not suffered a "material adverse change". Similarly, as a condition to further borrowings, the Company must certify that no event has occurred or failed to occur that has had or would reasonably be expected to have a materially adverse effect on the Company since the date of the last borrowing under this agreement. The Fleet agreement allows the Company to continue to borrow until such time that:

* a "material adverse effect" has occurred; or
* the Company no longer complies with all other provisions of the agreement, in which case further borrowing will not be permitted; or
* there has been a "material adverse change", in which case the banks may declare the Company in default.

Terms also call in part for a second priority mortgage lien and security interest in the collateral pledged under the first mortgage bond indenture.

On September 20, 2000, we established a $15.0 million revolving credit agreement ("KeyBank agreement") with KeyBank National Association ("KeyBank"). The KeyBank agreement is for a period of 364 days and will expire on September 19, 2001. Pursuant to a one year power supply option agreement between the Company and Energy East Corporation ("EE"), EE made a payment of $15.0 million to the Company. In exchange, the Company gave EE an option to purchase energy from certain wholly owned production facilities, for a period not to exceed 15 years, if the funds are not returned to EE upon request after September 2001. The Company was required to invest the funds provided by EE in a certificate of deposit at KeyBank pledged by the Company to secure the repayment of indebtedness issued under the Keybank agreement. At December 31, 2000, there was $15.0 million outstanding on the KeyBank Agreement.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2001. The VPSB Order of January 23, 2001 (the "Settlement Order") will likely permit restoration of the Company's investment grade debt ratings, allowing arrangement of such financing as the Company needs during 2001. On March 5, 2001, Moody's Investors Service upgraded the Company's first mortgage bond rating to Baa2 from Ba1, and upgraded the Company's preferred stock rating to baa3 from ba3. The rating action reflected Moody's earnings and cash flow expectations for the Company following the Settlement Order.

G. INCOME TAXES

Utility. The Company accounts for income taxes using the liability method. This method accounts for deferred income taxes by applying statutory rates to the differences between the book and tax bases of assets and liabilities.

The regulatory tax assets and liabilities represent taxes that will be collected from or returned to customers through rates in future periods. As of December 31, 2000 and 1999, the net regulatory assets were $1,908,000 and $1,805,000, respectively, and included in other deferred charges on the Company's consolidated balance sheets.

The temporary differences which gave rise to the net deferred tax liability at December 31, 2000 and December 31, 1999, were as follows:

AT DECEMBER 31,

(In thousands)	2000	1999
DEFERRED TAX ASSETS		
Contributions in aid of construction.	$10,018	$ 9,056
Deferred compensation and postretirement benefits.	4,122	3,372
Self insurance and other reserves . .	-	3,664
Other	1,958	1,183
	$16,098	$17,275
DEFERRED TAX LIABILITIES		
Property related.	$38,648	$37,921
Demand side management.	1,810	2,328
Deferred purchased power costs. . . .	84	2,202
Pine Street reserve	571	25
Other	629	-
	$41,742	$42,476
Net accumulated deferred income tax liability	$25,644	$25,201

The following table reconciles the change in the net accumulated deferred income tax liability to the deferred income tax expense included in the income statement for the period:

YEARS ENDED DECEMBER 31,

(In thousands)	2000	1999	1998
Net change in deferred income tax . . liability	$ 443	$1,812	$(112)
Change in income tax related regulatory assets and liabilities .	184	176	510
Change in alternative minimum tax credit.	-	-	(70)
Deferred income tax expense (benefit)	$ 627	$1,988	$ 328

The components of the provision for income taxes are as follows:

YEARS ENDED DECEMBER 31, (In thousands)	2000	1999	1998
Current federal income taxes .	$ (786)	$ (339)	$(1,047)
Current state income taxes . .	(249)	(125)	(366)
Total current income taxes . .	(1,035)	(464)	(1,413)
Deferred federal income taxes.	461	1,479	219
Deferred state income taxes. .	166	509	109
Total deferred income taxes. .	627	1,988	328
Investment tax credits-net . .	(283)	(282)	(282)
Income tax provision (benefit)	$ (691)	$1,242	$(1,367)

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

YEARS ENDED DECEMBER 31, (In thousands)	2000	1999	1998
Income (loss) before income taxes and preferred dividends	$(6,531)	$(1,821)	$(4,244)
Federal statutory rate.	34.0%	34.0%	34.0%
Computed "expected" federal income taxes	(2,221)	(619)	(1,443)
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation.	83	92	153
Dividends received and paid credit.	(435)	(485)	(480)
AFUDC-equity funds.	(33)	(5)	(36)
Amortization of ITC	(282)	(282)	(282)
State tax (benefit)	(83)	383	(256)
Excess deferred taxes	(60)	(60)	(60)
Tax attributable to subsidiaries.	2,213	2,271	845
Other	127	(53)	192
Total federal and state income tax (benefit).	$ (691)	$ 1,242	$(1,367)
Effective combined federal and state income tax rate	10.6%	(68.2%)	32.2%

Non-Utility. The Company's non-utility subsidiaries, excluding MEI, had accumulated deferred income taxes of approximately $2,000 on their balance sheets at December 31, 2000, attributable to depreciation timing differences.

The components of the provision for the income tax expense (benefit) for the non-utility operations are:

(In thousands)	YEARS ENDED DECEMBER 31, 2000	1999	1998
State income taxes	$ 7	$ 99	$(281)
Federal income taxes	21	310	(202)
Income tax expense (benefit)	$ 28	$ 409	$(483)

The effective combined federal and state income tax rates for the continuing non-utility operations were 34.0 percent, 34.0 percent, and 32.6 percent, for the years ended December 31, 2000, 1999 and 1998, respectively. See Note L for income tax information on the discontinued operations of MEI.

H. PENSION AND RETIREMENT PLANS.

The Company has a defined benefit pension plan covering substantially all of its employees. The retirement benefits are based on the employees' level of compensation and length of service. The Company's policy is to fund all accrued pension costs. The Company records annual expense and accounts for its pension plan in accordance with Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions. The Company provides certain health care benefits for retired employees and their dependents. Employees become eligible for these benefits if they reach normal retirement age while working for the Company. The Company accrues the cost of these benefits during the service life of covered employees. The pension plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities.

Accrued postretirement health care expenses are recovered in rates to the extent those expenses are funded. In order to maximize the tax-deductible contributions that are allowed under IRS regulations, the Company amended its pension plan to establish a 401-h sub-account and separate VEBA trusts for its union and non-union employees. The VEBA plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities. The following provides a reconciliation of benefit obligations, plan assets, and funded status of the plans as of December 31, 2000 and 1999.

	At and for the years ended December 31, Pension Benefits		Other Post-retirement Ben	
	2000	1999	2000	1999
(In thousands)				
Change in projected benefit obligation:				
Projected benefit obligation as of prior year end.	$22,444	$ 30,860	$11,955	$12,552
Service cost	655	620	216	240
Interest cost.	1,658	1,780	1,049	855
Special termination benefit.	-	5,385	-	1,446

Change in actuarial assumptions.	-	-	2,328	(1,372)
Settlements.	-	(9,527)	-	-
Actuarial (gain) loss.	513	(2,080)	73	(70)
Benefits paid.	(1,938)	(4,312)	(674)	(864)
Curtailment.	-	(282)	-	(832)
Projected benefit obligation as of year end. . . .	$23,332	$ 22,444	$14,947	$11,955
Change in plan assets:				
Fair value of plan assets as of prior year end . .	$31,477	$ 38,030	$11,062	$ 9,735
Contribution	-	-	-	-
Actual return on plan assets	(1,779)	7,286	(118)	1,327
Benefits paid.	(1,938)	(13,839)	-	-
Fair value of plan assets as of year end	$27,760	$ 31,477	$10,944	$11,062
Funded status as of year end	$ 4,428	$ 9,032	$(4,003)	$ (893)
Unrecognized transition obligation (asset)	(406)	(571)	3,936	4,264
Unrecognized prior service cost.	766	887	(577)	(635)
Unrecognized net actuarial gain.	(6,848)	(12,193)	(130)	(3,589)
Accrued benefits at year end	$(2,060)	$ (2,845)	$ (774)	$ (853)

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31, 2000, 1999, and 1998 were $346,000, $556,000, and $397,000, respectively, under this plan. This plan is funded in part through insurance contracts.

Net periodic pension expense and other postretirement benefit costs include the following components:

	For the years ended December 31,					
	Pension Benefits			Other Postretiremen		
(In thousands)	2000	1999	1998	2000	1999	1
Service cost	$ 655	$ 620	$ 787	$ 216	$ 240	$
Interest cost.	1,658	1,780	2,043	1,049	855	
Expected return on plan assets	(2,580)	(2,721)	(3,081)	(940)	(834)	(
Amortization of transition asset	(164)	(196)	(228)	-	-	
Amortization of net gain from earlier periods.	-	-	-	-	-	
Amortization of prior service cost	121	128	134	(58)	(60)	
Amortization of the transition obligation. . .	-	-	-	328	340	
Recognized net actuarial gain.	(474)	(196)	(195)	-	(19)	
Special termination benefit.	-	3,122	2,026	-	888	
Regulatory deferral.	-	(3,122)	(2,026)	-	(888)	
Net periodic benefit cost.	$ (784)	$ (585)	$ (540)	$ 595	$ 522	$

Assumptions used to determine postretirement benefit costs and the related benefit obligation were:

	Pension benefits 2000	Pension benefits 1999	Other Post-retirement Benefits 2000	Other Post-retirement Benefits 1999
For the years ended December 31,				
Weighted average assumptions as of year end:				
Discount rate.	7.50%	6.75%	7.50%	7.50%
Expected return on plan assets	9.00%	9.00%	8.50%	8.50%
Rate of compensation increase.	4.50%	4.00%	-	-
Medical inflation.	-	-	6.00%	5.30%

For measurement purposes, a 6 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2000 and later years. The health care cost trend rate assumption has a significant effect on the amounts reported. For example, increasing the assumed health care cost trend rate by one percentage point for all future years would increase the accumulated postretirement benefit obligation as of December 31, 2000 by $1.9 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2000 by $200,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2000 by $1.5 million, and the total of the service and interest cost components of net periodic postretirement cost for 2000 by $157,000.

In 1999, the Company deferred special termination pension benefit costs of $3,122,000 due to an early retirement program and other employee separation activities. Curtailment and settlement gains of $2.3 million are included in the special termination pension benefit cost. The special termination benefit recorded in 1998 resulted from the early retirement option offered to employees in 1998. Also in 1999, the Company deferred special termination postretirement benefit costs of $888,000 due to an early retirement program. Management believes that the amounts deferred are probable of recovery.

I. COMMITMENTS AND CONTINGENCIES

1. INDUSTRY RESTRUCTURING. The electric utility business is being subjected to rapidly increasing competitive pressures stemming from a combination of trends. Certain states, including all the New England states except Vermont, have enacted legislation to allow retail customers to choose their electric suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems. Recent power supply management difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards de-regulation in Vermont. There can be no assurance that any potential future restructuring plan ordered by the VPSB, the courts, or through legislation will include a mechanism that would allow for full recovery of our stranded costs and include a fair return on those costs as they are being recovered.

2. ENVIRONMENTAL MATTERS. The electric industry typically uses or generates a range of potentially hazardous products in its operations. The Company must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with those requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site. The Company maintains an environmental compliance and monitoring program that includes employee training, regular inspection of Company

facilities, research and development projects, waste handling and spill prevention procedures and other activities.

Pine Street Barge Canal Site. The Federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), commonly known as the "Superfund" law, generally imposes strict, joint and several liability, regardless of fault, for remediation of property contaminated with hazardous substances. The Company has been notified by the Environmental Protection Agency ("EPA") that it is one of several potentially responsible parties ("PRPs") for cleanup of the Pine Street Barge Canal site in Burlington, Vermont, where coal tar and other industrial materials were deposited.

In September 1999, we negotiated a final settlement with the United States, the State of Vermont, and other parties over terms of a Consent Decree that covers claims addressed in the earlier negotiations and implementation of the selected remedy. In November 1999, the Consent Decree was filed in the federal district court. The Consent Decree addresses claims by the EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site.

As of December 31, 2000, the Company's total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $23.5 million. This includes those amounts not recovered in rates, amounts recovered in rates, and amounts for which rate recovery has been sought but which are presently awaiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier, and more costly, proposals for the site, as well as litigation and related costs necessary to obtain settlements with insurers and other PRP's to provide amounts required to fund the clean up (remediation costs) and to address liability claims at the site. A smaller amount of past expenditures was for site-related response costs, including costs incurred pursuant to the EPA and State orders that resulted in funding response activities at the site, and to reimbursing the EPA and the State for oversight and related response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be $12.4 million over the next 33 years. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We also have recorded an offsetting regulatory asset and we believe that it is probable that we will receive future revenues to recover these costs. Although it did not eliminate the rate base deferral of these expenditures, or make any specific order in this regard, the VPSB indicated that it was inclined to agree with other parties in the case that the ultimate costs associated with the Pine Street Barge Canal site, taking into account recoveries from insurance carriers and other PRPs, should be shared between customers and shareholders of the Company. In response to our Motion for Reconsideration, the VPSB on June 8, 1998 stated its intent was "to reserve for a future docket issues pertaining to the sharing of remediation-related costs between the Company and its customers". The VPSB Order released January 23, 2001 regarding the Company's 1998 retail rate request did not change the status of Pine Street cost recovery.

Clean Air Act. The Company purchases most of its power supply from other utilities and does not anticipate that it will incur any material direct costs as a result of the Federal Clean Air Act or proposals to make more stringent regulations under that Act.

3. OPERATING LEASES. The Company terminated an operating lease for its corporate headquarters building and two of its service center buildings in the first quarter of 1999. During 1998, the Company recorded a loss of approximately $1.9 million before applicable income taxes to reflect the probable loss resulting from this transaction. The Company sold its corporate headquarters building in 1999, but retained ownership of the two service centers.

4. JOINTLY-OWNED FACILITIES. The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2000, as follows:

	Ownership Interest	Share of Capacity	Utility Plant	Accumulated Depreciation
	(In %)	(In MWh)	(In thousands)	
Highgate	33.8	67.6	$ 10,299	$ 4,118
McNeil	11.0	5.9	8,866	4,484
Stony Brook (No. 1). . .	8.8	31	10,339	7,636
Wyman (No. 4).	1.1	6.8	1,980	1,192
Metallic Neutral Return.	59.4	-	$ 1,563	$ 619

Metallic Neutral Return is a neutral conductor for NEPOOL/Hydro-Quebec Interconnection

The Company's share of expenses for these facilities is reflected in the Consolidated Statements of Income. Each participant in these facilities must provide its own financing.

5. RATE MATTERS.

RETAIL RATE CASES- On March 2, 1998, the VPSB released its Order dated February 27, 1998 in the then pending rate case. The VPSB authorized us to increase our rates by 3.61 percent, which gave us increased annual revenues of $5.6 million. The VPSB Order denied us the right to charge customers $5.48 million of the annual costs for power purchased under our contract with Hydro-Quebec. The VPSB denied recovery of these costs for the following reasons:

* the VPSB claimed that we had acted imprudently by committing to the power contract with Hydro-Quebec in August 1991 (the imprudence disallowance); and
* to the extent that the costs of power to be purchased from Hydro-Quebec were then higher than current estimates of market prices for power during the contract term, after accounting for the imprudence disallowance, the contract power was not "used and useful".

On May 8, 1998, we filed a request with the VPSB to increase our retail rates by 12.93 percent due to higher power costs, the cost of the January 1998 ice storm, and investments in new plant and equipment.

On November 18, 1998, by Memorandum of Understanding ("MOU"), the Company, the Department and IBM agreed to stay rate proceedings in the 1998 rate case until or after September 1, 1999, or such earlier date as the parties may later agree to or the VPSB may order. The agreement to suspend our 1998 rate case delayed the date of a final decision on the 1998 rate case to December 15, 1999, and we recognized an additional loss of $5.25 million in the last quarter of 1998 representing the effect of the continued disallowance of Hydro-Quebec costs through December 15, 1999. The MOU provided for a 5.5% temporary retail rate increase, to produce $8.9 million in annualized additional revenue, effective with service rendered December 15, 1998. An additional surcharge was permitted, without further VPSB order, in order to produce additional revenues necessary to provide the Company with the capacity to finance 1999 Pine Street Barge Canal site expenditures. The MOU was approved by the VPSB on December 11, 1998. The MOU did not provide for any specific disallowance of power costs under our purchase power contract with Hydro-Quebec. Issues respecting recovery of such power costs were preserved for future proceedings.

The stay and suspension of this pending rate case and the temporary rate levels agreed to in the MOU were designed to allow us to continue to provide adequate and efficient service to our customers while we sought mitigation of power supply costs.

On September 7 and December 17, 1999, the VPSB issued Orders approving two amendments to the MOU that the Company had entered into with the Department and IBM. The two amendments continued the stay of proceedings until September 1, 2000, with a final decision expected by December 31, 2000. The amendments maintained the other features of the original MOU, and the second amendment provided for a temporary rate increase of 3 percent, in addition to the prior temporary rate level, to become effective as of January 1, 2000.

The Company reached a final settlement agreement with the VDPS in the pending rate case during November 2000. The final settlement agreement contains the following provisions:

* A rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases became permanent;
* Rates set at levels that recover the Company's Hydro-Quebec contract costs, effectively ending the regulatory disallowances experienced by the Company over the past three years;
* The Company agrees not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;
* The Company agrees to write off approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaces short-term credit facilities with long-term debt or equity financing;
* Seasonal rates will be eliminated in April 2001, which is expected to generate approximately $6.0 million in cash flow that can be utilized to offset increased costs during 2001, 2002 and 2003; and
* The Company agrees to consult extensively with the DPS regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions:

* The Settlement Order requires the Company and customers to share equally any premium above book value realized by the Company, subject to an $8.0 million limit on the customers' share, in any future merger, acquisition or asset sale; and
* The second condition restricts Company investments in non-utility operations.

6. TRANSMISSION. A FERC ruling in December 2000 required ISO New England to revise its installed capability ("ICAP") deficiency charge of $0.17 per kw month to $8.75 per kw month retroactive to August 1, 2000. On January 10, 2001, the FERC suspended its order "to ensure that bills for past periods will not be assessed until the Commission has considered the pending requests for rehearing,

which, if successful, would then require extensive refunds and surcharges". Numerous requests for rehearing challenging the imposition of the new rate have been filed by New England utilities and state commissions. If the FERC does not change its initial order as a result of the rehearings, the Company would be required to pay ISO New England approximately $1.4 million related to 2000. Management does not believe that the retroactive application of the ICAP revision is probable.

7. DEFERRED CHARGES NOT INCLUDED IN RATE BASE. The Company has incurred and deferred approximately $3.0 million in costs for tree trimming, storm damage and federal regulatory commission work of which $2.8 million will be amortized over five years ending in December 2005. Currently, the Company amortizes such costs based on historical averages and does not receive a return on amounts deferred. Management expects to seek and receive ratemaking treatment for these costs in future filings.

The Settlement Order directed the Company to write-off deferred charges applicable to the state regulatory commission of $3.2 million as part of the rate case agreement with the DPS. The charge is included in other operating expense for the year ended December 31, 2000. The Settlement Order requires the remaining balance and future expenditures of deferred regulatory commission charges be amortized over seven years.

8. OTHER LEGAL MATTERS. The Company is involved in legal and administrative proceedings in the normal course of business and does not believe that the ultimate outcome of these proceedings will have a material effect on the financial position or the results of operations of the Company.

J. OBLIGATIONS UNDER TRANSMISSION INTERCONNECTION SUPPORT AGREEMENT

Agreements executed in 1985 among the Company, VELCO and other NEPOOL members and Hydro-Quebec provided for the construction of the second phase (Phase II) of the interconnection between the New England electric systems and that of Hydro-Quebec. Phase II expands the Phase I facilities from 690 megawatts to 2,000 megawatts and provides for transmission of Hydro-Quebec power from the Phase I terminal in northern New Hampshire to Sandy Pond, Massachusetts. Construction of Phase II commenced in 1988 and was completed in late 1990. The Company is entitled to 3.2 percent of the Phase II power-supply benefits. Total construction costs for Phase II were approximately $487 million. The New England participants, including the Company, have contracted to pay monthly their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. As a supporting participant, the Company must make support payments under thirty-year agreements. These support agreements meet the capital lease accounting requirements under SFAS 13. At December 31, 2000, the present value of the Company's obligation is approximately $6.4 million.

Projected future minimum payments under the Phase II support agreements are as follows:

	YEAR ENDING DECEMBER 31, (In thousands)
2001.	$ 430
2002.	430
2003.	430
2004.	430

2005.		430
Total for 2006-2020		4,299
Total	$	6,449

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company and New England Hydro-Transmission Corporation, subsidiaries of New England Electric System, in which certain of the Phase II participating utilities, including the Company, own equity interests. The Company holds approximately 3.2 percent of the equity of the corporations owning the Phase II facilities.

K. LONG-TERM POWER PURCHASES

1. Unit Purchases. Under long-term contracts with various electric utilities in the region, the Company is purchasing certain percentages of the electrical output of production plants constructed and financed by those utilities. Such contracts obligate the Company to pay certain minimum annual amounts representing the Company's proportionate share of fixed costs, including debt service requirements whether or not the production plants are operating. The cost of power obtained under such long-term contracts, including payments required when a production plant is not operating, is reflected as "Power Supply Expenses" in the accompanying Consolidated Statements of Income.

Information (including estimates for the Company's portion of certain minimum costs and ascribed long-term debt) with regard to significant purchased power contracts of this type in effect during 2000 follows:

	STONY BROOK	VERMONT YANKEE
	(Dollars in thousands)	
Plant capacity.	352.0 MW	531.0 MW
Company's share of output	4.40%	17.90%
Contract period	(1)	(2)
Company's annual share of:		
Interest	$ 189	$ 2,397
Other debt service	347	
Other capacity	497	25,401
Total annual capacity	$ 1,033	$27,798
Company's share of long-term debt	$ 3,194	$17,181

(1) Life of plant estimated to be 1981 - 2006.
(2) License for plant operations expires in 2012.

2. Hydro-Quebec System Power Purchase and Sale Commitments. Under various contracts, the details of which are described in the table below, the Company purchases capacity and associated energy produced by the Hydro-Quebec system. Such contracts obligate the Company to pay certain fixed capacity costs whether or not energy purchases above a minimum level set forth in the contracts are made. Such minimum energy purchases must be made whether or not other, less

expensive energy sources might be available. These contracts are intended to complement the other components in the Company's power supply to achieve the most economic power-supply mix reasonably available.

The Company's current purchases pursuant to the contract with Hydro-Quebec entered into December 4, 1987 (the 1987 Contract) are as follows: (1) Schedule B -- 68 megawatts of firm capacity and associated energy to be delivered at the Highgate interconnection for twenty years beginning in September 1995; and (2) Schedule C3 -- 46 megawatts of firm capacity and associated energy to be delivered at interconnections to be determined at any time for 20 years, which began in November 1995.

During 1994, the Company negotiated an arrangement with Hydro-Quebec that reduces the cost impacts associated with the purchase of Schedules B and C3 under the 1987 Contract, over the November 1995 through October 1999 period (the July 1994 Agreement). Under the July 1994 Agreement, the Company, in essence, will take delivery of the amounts of energy as specified in the 1987 Contract, but the associated fixed costs will be significantly reduced from those specified in the 1987 Contract.

As part of the July 1994 Agreement, we were obligated to purchase $4.0 million (in 1994 dollars) worth of research and development work from Hydro-Quebec over a period ending October 1999(which has since been extended), and made an additional $6.5 million (plus accrued interest) payment to Hydro-Quebec in 1995. Hydro-Quebec retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2000 to 2015 period, if documented drought conditions exist in Quebec. The period for completing the research and development purchase was subsequently extended to March 2001.

During the first year of the July 1994 Agreement (the period from November 1995 through October 1996), the average cost per kilowatt-hour of Schedules B and C3 combined was cut from 6.4 to 4.2 cents per kilowatt-hour, a 34 percent (or $16 million) cost reduction. Over the period from November 1996 through December 2000 and accounting for the payments to Hydro-Quebec, the combined unit costs will be lowered from 6.5 to 5.9 cents per kilowatt-hour, reducing unit costs by 10 percent and saving $20.7 million in nominal terms.

All of the Company's contracts with Hydro-Quebec call for the delivery of system power and are not related to any particular facilities in the Hydro-Quebec system. Consequently, there are no identifiable debt-service charges associated with any particular Hydro-Quebec facility that can be distinguished from the overall charges paid under the contracts.

A summary of the Hydro-Quebec contracts through the July 1994 Agreement, including historic and projected charges for the years indicated, follows:

THE 1987 CONTRACT	
SCHEDULE B	SCHEDULE C3

(Dollars in thousands except per KWh

Capacity acquired			68 MW		46 MW
Contract period.			1995-2015		1995-2015
Minimum energy purchase. (annual load factor)			75%		75%
Annual energy charge . .	2000	$	10,471		$ 7,105
estimated.	2001-2015		13,506	*	9,320
Annual capacity charge .	2000		16,850		11,727
estimated.	2001-2015		16,686	*	11,523
Average cost per KWh . .	2000	$	0.068		$ 0.069
estimated.	2001-2015	$	0.070	**	$ 0.070

*Estimated average
**Estimated average in nominal dollars levelized over the period indicated
Includes amortization of payments to Hydro-Quebec for the July 1994 Agreement

Under a 1996 arrangement (the "9601 arrangement"), the Company is required to shift up to 40 megawatts of its Schedule C3 to an alternate transmission path and use the associated portion of the NEPOOL/Hydro-Quebec interconnection facilities to purchase power for the period from September 1996 through June 2001 at prices that vary based upon conditions in effect when the purchases were made. The 9601 arrangement also provides for minimum payments by the Company to Hydro-Quebec for the periods in which power is not purchased under the arrangement. The 9601 arrangement allows Hydro-Quebec to curtail energy deliveries should it need to use certain resources to supplement available supply. During the last three months of 2000, Hydro-Quebec did curtail energy deliveries. Although the level of benefits to the Company will depend on various factors, the Company estimates that the 9601 arrangement will provide a benefit of approximately $3.0 million on a net present value basis.

Under a separate agreement executed on December 5, 1997 (the "9701 arrangement"), Hydro-Quebec provided a payment of $8.0 million to the Company in 1997. In return for this payment, the Company provided Hydro-Quebec an ongoing option for the purchase of power. Commencing April 1, 1998, and effective through October 2015, Hydro-Quebec can exercise an option to purchase up to 52,500 MWh ("option A") on an annual basis, at energy prices established in accordance with the 1987 Contract. The cumulative amount of energy purchased under the 9701 arrangement shall not exceed 950,000 MWh. Hydro-Quebec's option to curtail energy deliveries pursuant to the July 1994 Agreement may be exercised in addition to these purchase options.

Over the same period, Hydro-Quebec can exercise an option on an annual basis to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy price. Hydro-Quebec can purchase no more than 200,000 MWh in any given contract year ending October 31. As of December 31, 2000, Hydro-Quebec had purchased or called to purchase 349,000 MWh under option B, including calls for January and February of 2001.

In 2000, Hydro-Quebec called for deliveries to third parties at a net cost to the Company of approximately $14.0 million (including the cost of the January and February 2001 calls and related financial positions), which was due to higher energy replacement costs. Approximately $6.6 million of the 9701 arrangement costs are recovered currently in rates on an annual basis. The VPSB, in the Settlement Order said, "The record does not demonstrate that any other New England utility foresaw the extent and degree of volatility that has developed in the New England wholesale power markets. Absent that volatility, the 97-01 Agreement would not have had adverse effects." In conjunction with the Settlement Order, Hydro-Quebec committed to the DPS that it would not call any energy under option B of the 9701 arrangement during 2002. In 1999, Hydro-Quebec called for deliveries to third parties at a net cost to the Company of approximately $6.3 million. The Company's estimate of the fair value of the future net cost for the 9701 arrangement, which is dependent upon the timing of any exercise of options, and the market price for replacement power, is between $24.5 and $29.5 million. Future estimates could change by a material amount.

In 1999, the Company and the other Vermont Joint Owners (VJO) of the Hydro-Quebec contract initiated an arbitration against Hydro-Quebec, pursuant to the 1987 Contract terms, to determine whether the suspension of deliveries of power to Vermont during and after the January 1998 ice storm evidenced a default by Hydro-Quebec under the terms of the contract. Hydro-Quebec maintains that the "force majeure" (superior or irreversible force) provision in the 1987 Contract applies, which could excuse its non-delivery of power under these circumstances. Arbitration of the dispute may lead to remedies having a material impact on our contractual obligation, including the possibility that the 1987 Contract be declared terminated or void. If arbitration results in a cash payment, it will first be applied to a regulatory asset of $4.7 million for arbitration litigation costs. If the 1987 Contract is declared terminated or void, the Company would have to replace a substantial amount of its power needs at terms which could materially exceed the 1987 Contract price for 2001. The Company believes that it could contract replacement power at costs substantially below the long term costs of the 1987 Contract. The Settlement Order provides that the Company will not earn a return on these litigation costs, unless the case results in lower power supply costs for ratepayers. A decision is expected in this arbitration in April 2001.

3. Morgan Stanley Agreement - On February 11, 1999, the Company entered into a contract with Morgan Stanley Capital Group, Inc. (MS). In January 2001, the MS contract was modified and extended to December 31, 2003. The contract provides us a means of managing price risks associated with changing fossil fuel prices. On a daily basis, and at MS's discretion, the Company will sell power to MS from either (i) all or part of our portfolio of power resources at predefined operating and pricing parameters or (ii) any power resources available to the Company, provided that sales of power from sources other than Company-owned generation comply with the predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements. MS is also responsible for scheduling supply resources. The Company remains responsible for resource performance and availability. MS provides no coverage against major unscheduled outages.

L. DISCONTINUED OPERATIONS.

The Company has decided to sell or otherwise dispose of the operations and assets of MEI, which owns and invests in energy generation, energy efficiency, and wastewater treatment projects. MEI has been reported as a separate segment in 1998 and prior years, and appeared as a separate "Equity investment in energy related business" caption in the nonutility section of the consolidated balance sheet. Results of operations were previously included in the section Other Income in the consolidating statements of income. In 1999 and 2000, assets and liabilities are presented net in the nonutility section as "Business segment held for disposal", or "Liability of discontinued segment". The provisions for loss from discontinued operations reflect management's current estimate. Risk factors associated with the discontinuation of MEI operations include the outcome of warranty litigation, and future cash requirements necessary to minimize costs of winding down wastewater operations. Several municipalities using wastewater treatment equipment have commenced or threatened litigation. The ultimate loss remains subject to the disposition of remaining assets and liabilities, and could exceed the amounts recorded. The following illustrates the results and financial statement impact of MEI during and at the periods shown:

	2000	1999	1998

(In thousands except per share)			
Revenues	$ 1,546	$ 2,296	$ 2,092
Net income (loss) operations	$ -	$ (603)	$(2,086)
Provisions for loss on disposal and future operating losses.	(6,549)	(6,676)	-
Net income (loss).	$(6,549)	$(7,279)	$(2,086)
Net income (loss) per share.	$ (1.19)	$ (1.36)	$ (0.40)

Income taxes for MEI for the years ended December 31, 2000, 1999 and 1998 are summarized as:

YEARS ENDED DECEMBER 31,

(In thousands)	2000	1999	1998
State income taxes	$(1,064)	$ (281)	$ (222)
Federal income taxes	(3,349)	(1,371)	(1,130)
Investment tax credits . . .	-	-	(111)
Income tax expense (benefit)	$(4,413)	$(1,652)	$(1,463)

M. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following quarterly financial information, in the opinion of management, includes all adjustments necessary to a fair statement of results of operations for such periods. Variations between quarters reflect the seasonal nature of the Company's business and the timing of rate changes.

2000 Quarter ended

(Amounts in thousands except per share data)	MARCH	JUNE	SEPTEMBER	DECEMBER	TOTAL
Operating revenues.	$67,712	$61,927	$ 78,143	$ 69,544	$277,32
Operating income (loss)	4,613	(2,997)	3,271	373	5,26
Net income (loss) from continuing operations.	$ 3,449	$(4,375)	$ 1,961	$ (1,340)	$ (30
Net loss from discontinued operations.	-	(1,530)	-	(5,019)	(6,54
Net Income (loss) applicable to common stock.	$ 3,449	$(5,905)	$ 1,961	$ (6,359)	$ (6,85
Earnings (loss) per average share from:					
Continuing operations	$ 0.63	$ (0.80)	$ 0.36	$ (0.25)	$ (0.0
Discontinued operations	-	(0.28)	-	(0.91)	(1.1
Basic and diluted	$ 0.63	$ (1.08)	$ 0.36	$ (1.16)	$ (1.2

Weighted average common shares outstanding. .	5,437	5,472	5,505	5,551	5,49

1999 Quarter ended

(Amounts in thousands except per share data)	MARCH	JUNE	SEPTEMBER	DECEMBER	TOT
Operating revenues.	$59,018	$59,535	$ 68,478	$ 64,017	$251,
Operating income.	3,906	977	1,412	1,651	7,
Net income (loss) from continuing operations.	$ 3,170	$ (412)	$ (115)	$ 418	$ 3,
Net loss from discontinued operations.	(522)	(81)	(4,592)	(2,084)	(7,
Net Income (loss) applicable to common stock.	$ 2,648	$ (493)	$ (4,707)	$ (1,666)	$ (4,
Earnings (loss) per average share from:					
Continuing operations	$ 0.60	$ (0.08)	$ (0.02)	$ 0.07	$ 0
Discontinued operations	(0.10)	(0.02)	(0.85)	(0.39)	(1
Basic and diluted	$ 0.50	$ (0.10)	$ (0.88)	$ (0.31)	$ (0
Weighted average common shares outstanding. .	5,318	5,344	5,374	5,291	5,

1998 Quarter ended

(Amounts in thousands except per share data)	MARCH	JUNE	SEPTEMBER	DECEMBER	TOT
Operating revenues.	$46,932	$43,733	$ 47,984	$ 45,655	$184,
Operating income.	316	2,811	3,147	(802)	5,
Net income (loss) from continuing operations.	$(2,648)	$ 1,286	$ 1,811	$ (2,536)	$ (2,
Net loss from discontinued operations	(757)	(355)	(178)	(796)	(2,
Net income (loss) applicable to common stock.	$(3,405)	$ 931	$ 1,633	$ (3,332)	$ (4,
Earnings (loss) per average share from:					
Continuing operations	$ (0.51)	$ 0.25	$ 0.34	$ (0.48)	$ (0
Discontinued operations	(0.15)	(0.06)	(0.03)	(0.16)	(0
Basic and diluted	$ (0.66)	$ 0.18	$ 0.31	$ (0.63)	$ (0
Weighted average common shares outstanding. .	5,196	5,222	5,261	5,291	5,

69

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of
Green Mountain Power Corporation:

We have audited the accompanying consolidated balance sheets and consolidated capitalization data of Green Mountain Power Corporation (a Vermont corporation) and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. 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 audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and its subsidiaries as of December 31, 2000 and 1999, and the consolidated results of its operations and cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

/s/ Arthur Anderson
Boston, Massachusetts
February 2, 2001

Schedule II
GREEN MOUNTAIN POWER CORPORATION
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended December 31, 2000, 1999, and 1998

	Balance at Beginning of Period	Additions Charged to Cost & Expenses	Additions Charged to Other Accounts	Balance at End of Deductions	Period
Injuries and Damages (1)					
2000	$ 10,129,130	$ 111,667	$ 3,193,383	$ 51,467	$13,382,
1999	7,898,785	100,000	3,814,874	1,684,529	10,129,
1998	663,785	2,735,000	5,000,000	500,000	7,898,
Bad Debt Reserve					
2000	390,495	35,395	-	-	425,
1999	400,000	261,697	12,762	283,964	390,
1998(2).	493,405	393,949	83,299	570,653	400,

(1) Includes Pine Street Barge Canal reserves
(2) Includes non-utility bad debt reserve.

71

Exhibit 23-a-1

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated February 2, 2001 included in this Form 10-K into the Company's previously filed Registration Statements on Form S-3, File Nos. 33-58411 and 33-59383, and into the Company's previously filed Registration Statements on Form S-8, File Nos. 33-58413 and 33-60511. It should be noted that we have not performed any audit procedures subsequent to December 31, 2000 or performed any audit procedures subsequent to the date of our report.

Boston, Massachusetts
March 21, 2001 /s/ Arthur Andersen LLP

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

We have audited, in accordance with generally accepted auditing standards, the consolidated financial statements of Green Mountain Power Corporation included in this Form 10-K and have issued our report thereon dated February 2, 2001. Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule listed in the accompanying index to consolidated financial statements and schedules is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic consolidated financial statements. This schedule has been subjected to the auditing procedures applied in the audit of the basic consolidated financial statements, and in our opinion, fairly states, in all material respects, the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

Boston, Massachusetts
February 2, 2001 /s/ Arthur Andersen LLP

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

PART III

ITEMS 10, 11, 12 & 13

Certain information regarding executive officers called for by Item 10, "Directors and Executive Officers of the Registrant," is furnished under the caption, "Executive Officers" in Item 1 of Part I of this Report. The other information called for by Item 10, as well as that called for by Items 11, 12, and 13, "Executive Compensation," "Security Ownership of Certain Beneficial Owners and Management" and "Certain Relationships and Related Transactions," will be set forth under the captions "Election of Directors," Board Compensation, Other Relationship, Meetings and Committees, "Section 16(a) Beneficial Ownership Reporting Compliance," "Executive Compensation," Compensation Committee Report on Executive Compensation, Performance Graphs, "Pension Plan Information" and "Securities Ownership of Certain Beneficial Owners and Management" in the Company's definitive proxy statement relating to its annual meeting of stockholders to be held on May 17, 2001. Such information is incorporated herein by reference. Such proxy statement pertains to the election of directors and other matters. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A in March 2001.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

Item 14(a)1. Financial Statements and Schedules. The financial statements and financial statement schedules of the Company are listed on the Index to financial statements set forth in Item 8 hereof.

Item 14(b) The following filings on Form 8-K were filed by the company on the topics and dates indicated:

November 13, 2000 announced the negotiation of a final rate settlement with the Vermont Department of Public Service.

November 15, 2000 announced a revised offer for the purchase of the Vermont Yankee nuclear generating plant was accepted by Vermont Yankee from AmerGen Energy Company.

January 5, 2001 announced continued mediation with Local 300 of the International Brotherhood of Electrical Workers, which had gone on strike that week resulting in the need for a federal mediator.

January 23, 2001 announced the Vermont Public Service Board Order approving the rate case settlement between the Company and the Vermont Department of Public Service, allowing a 3.42 percent increase in electric rates, and making permanent the two prior temporary rate increases.

January 26, 2001 announced Local 300 of the International Brotherhood of Electrical Workers voted to end the strike and ratify the new proposed contract, which included a provision for a second shift crew.

February 14, 2001 announced the Vermont Public Service Board Order Dismissing

Petition in Docket Number 6300, in which the Board determined that the revised offer by AmerGen Energy Company for the purchase of Vermont Yankee's nuclear generating plant did not reflect the fair market value of the plant, and dismissed the petition for approval.
March 6, 2001 announced the credit rating upgrade by Moody's Investor Service of the Company's first mortgage bonds from Ba1 to Baa2, and the upgrade of the Company's preferred stock from ba3 to baa3.

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

ITEM 14(A)3 AND ITEM 14(C). EXHIBITS SEC DOCKET

DESCRIPTION	INCORPORATED BY REFERENCE OR EXHIBIT	PAGE FILED HEREWITH
Restated Articles of Association, as certified. . . . June 6, 1991.	3-a	Form 10-K 1993 (1-8291)
Amendment to 3-a above, dated as of May 20, 1993. . .	3-a-1	Form 10-K 1993
Amendment to 3-a above, dated as of October 11, 1996.	3-a-2	Form 10-Q Sept. 19
By-laws of the Company, as amended. . . . . February 10, 1997.	3-b	Form 10-K 1996 (1-8291)
Indenture of First Mortgage and Deed of Trust . . . . dated as of February 1, 1955.	4-b	2-27300
First Supplemental Indenture dated as of. . . . . . . April 1, 1961.	4-b-2	2-75293
Second Supplemental Indenture dated as of . . . . . . January 1, 1966.	4-b-3	2-75293
Third Supplemental Indenture dated as of. . . . . . . July 1, 1968.	4-b-4	2-75293
Fourth Supplemental Indenture dated as of . . . . . . October 1, 1969.	4-b-5	2-75293
Fifth Supplemental Indenture dated as of. . . . . . . December 1, 1973.	4-b-6	2-75293
Seventh Supplemental Indenture dated as . . . . August 1, 1976.	4-a-7	2-99643
Eighth Supplemental Indenture dated as of . . . . . . December 1, 1979.	4-a-8	2-99643
Ninth Supplemental Indenture dated as of. . . . . . . July 15, 1985.	4-b-9	2-99643
Tenth Supplemental Indenture dated as of. . . . . . . June 15, 1989.	4-b-10	Form 10-K 1989 (1-8291)
Eleventh Supplemental Indenture dated as of . . . . . September 1, 1990.	4-b-11	Form 10-Q Sept. 1990 (1-8291)
Twelfth Supplemental Indentrue dated as of. . . . . . March 1, 1992.	4-b-12	Form 10-K 1991 (1-8291)
Thirteenth Supplemental Indenture dated as of . . . . March 1, 1992.	4-b-13	Form 10-K 1991 (1-8291)
Fourteenth Supplemental Indenture dated as of . . . . November 1, 1993.	4-b-14	Form 10-K 1993 (1-8291)
Fifteenth Supplemental Indenture dated as of. . . . . November 1, 1993.	4-b-15	Form 10-K 1993 (1-8291)
Sixteenth Supplemental Indenture dated as of.	4-b-16	Form 10-K 1995

December 1, 1995.		(1-8291)
Revised form of Indenture as filed as an Exhibit. . . to Registration Statement No. 33-59383.	4-b-17	Form 10-Q Sept. 1995 (1-8291)
Credit Agreement by and among Green Mountain Power. . The Bank of Nova Scotia, State Street Bank and Trust Company, Fleet National Bank, and Fleet National Bank, as Agent	4-b-18	Form 10-K 1997 (1-8291)
Amendment to Exhibit 4-b-18	4-b-18(a)	Form 10-Q Sept. 19
Form of Insurance Policy issued by Pacific. . . . . . Insurance Company, with respect to indemnification of Directors and Officers.	10-a	33-8146
Firm Power Contract dated September 16, 1958, ... between the Company and the State of Vermont and supplements thereto dated September 19, 1958; November 15, 1958; October 1, 1960 and February 1, 1964.	13-b	2-27300
Power Contract, dated February 1, 1968, between . . . the Company and Vermont Yankee Nuclear Power Corporation.	13-d	2-34346
Amendment, dated June 1, 1972, to Power Contract. . . between the Company and Vermont Yankee Nuclear Power Corporation.	13-f-1	2-49697
Amendment, dated April 15, 1983, to Power . . . . . . Contract between the Company and Vermont Yankee Nuclear Power Corporation.	10-b-3(a)	33-8164
Additional Power Contract, dated. . . . . February 1, 1984,between the Company and Vermont Yankee Nuclear Power Corporation.	10-b-3(b)	33-8164
Capital Funds Agreement, dated February 1,. . . . . . 1968, between the Company and Vermont Yankee Nuclear Power Corporation.	13-e	2-34346
Amendment, dated March 12, 1968, to Capital . . . . . Funds Agreement between the Company and Vermont Yankee Nuclear Power Corporation.	13-f	2-34346
Guarantee Agreement, dated November 5, 1981,. . . . . of the Company for its proportionate share of the obligations of Vermont Yankee Nuclear Power Corporation under a $40 million loan arrangement.	10-b-6	2-75293
Three-Party Power Agreement among the Company,. . . . VELCO and Central Vermont Public Service Corporation dated November 21, 1969.	13-i	2-49697
Amendment to Exhibit 10-b-7, dated June 1, 1981.. . .	10-b-8	2-75293
Three-Party Transmission Agreement among the. . . . . Company, VELCO and Central Vermont Public Service Corporation, dated November 21, 1969.	13-j	2-49697
Amendment to Exhibit 10-b-9, dated June 1, 1981.. . .	10-b-10	2-75293
Agreement with Central Maine Power Company et al, to enter into joint ownership of Wyman plant, dated November 1, 1974.		5.16
New England Power Pool Agreement as amended to November 1, 1975.		4.8
Bulk Power Transmission Contract between the. . . . . Company and VELCO dated June 1, 1968.	13-v	2-49697
Amendment to Exhibit 10-b-16, dated June 1, 1970. . .	13-v-i	2-49697
Power Sales Agreement, dated August 2, 1976, as . . . amended October 1, 1977, and related Transmission Agreement, with the Massachusetts Municipal Wholesale Electric Company.	10-b-20	33-8164
Agreement dated October 1, 1977, for Joint. . . . . . Ownership, Construction and Operation of the	10-b-21	33-8164

MMWEC Phase I Intermediate Units, dated October 1, 1977.		
Contract dated February 1, 1980, providing for. . . . the sale of firm power and energy by the Power Authority of the State of New York to the Vermont Public Service Board.	10-b-28	33-8164
Bulk Power Purchase Contract dated April 7, ... 1976, between VELCO and the Company.	10-b-32	2-75293
Agreement amending New England Power Pool . . . . . . Agreement dated as of December 1, 1981, providing for use of transmission inter-connection between New England and Hydro-Qubec.	10-b-33	33-8164
Phase I Transmission Line Support Agreement . . . . . dated as of December 1, 1981, and Amendment No. 1 dated as of June 1, 1982, between VETCO and participating New England utilities for construction, use and support of Vermont facilities of transmission interconnection between New England and Hydro-Qubec.	10-b-34	33-8164
Phase I Terminal Facility Support Agreement . . . . . dated as of December 1, 1981, and Amendment No. 1 dated as of June 1, 1982, between New England Electric Transmission Corporation and participating New England utilities for construction, use and support of New Hampshire facilities of transmission interconnection between New England and Hydro-Qubec.	10-b-35	33-8164
Agreement with respect to use of Quebec . . . . Interconnection dated as of December 1, 1981, among participating New England utilities for use of transmission interconnection between New England and Hydro-Qubec.	10-b-36	33-8164
Vermont Participation Agreement for Quebec. . . . . . Interconnection dated as of July 15, 1982, between VELCO and participating Vermont utilities for allocation of VELCO's rights and obligations as a participating New England utility in the transmission inter-connection between New England and Hydro-Qubec.	10-b-39	33-8164
Vermont Electric Transmission Company, Inc. . . . . . Capital Funds Agreement dated as of July 15, 1982, between VETCO and VELCO for VELCO to provide capital to VETCO for construction of the Vermont facilities of the transmission inter-connection between New England and Hydro-Qubec.	10-b-40	33-8164
VETCO Capital Funds Support Agreement dated as. . . . of July 15, 1982, between VELCO and participating Vermont utilities for allocation of VELCO's obligation to VETCO under the Capital Funds Agreement.	10-b-41	33-8164
Energy Banking Agreement dated March 21, 1983,. . . . among Hydro-Qubec, VELCO, NEET and parti-cipating New England utilities acting by and through the NEPOOL Management Committee for terms of energy banking between participating New England utilities and Hydro-Qubec.	10-b-42	33-8164
Interconnection Agreement dated March 21, 1983, . . . between Hydro-Qubec and participating New England utilities acting by and through the NEPOOL Management Committee for terms and	10-b-43	33-8164

conditions of energy transmission between New England and Hydro-Qubec.			
Energy Contract dated March 21, 1983, between . . . . Hydro-Qubec and participating New England utilities acting by and through the NEPOOL Management Committee for purchase of surplus energy from Hydro-Qubec.	10-b-44		33-8164
Agreement for Joint Ownership, Construction and . . . Operation of the Highgate Transmission Interconnection, dated August 1, 1984, between certain electric distribution companies, including the Company.	10-b-50		33-8164
Highgate Operating and Management Agreement,. . . . . dated as of August 1, 1984, among VELCO and Vermont electric-utility companies, including the Company.	10-b-51		33-8164
Allocation Contract for Hydro-Qubec Firm Power. . . . dated July 25, 1984, between the State of Vermont and various Vermont electric utilities, including the Company.	10-b-52		33-8164
Highgate Transmission Agreement dated as of . . . . . August 1, 1984, between the Owners of the Project and various Vermont electric distribution companies.	10-b-53		33-8164
Agreements entered in connection with Phase II. . . . of the NEPOOL/Hydro-Qubec + 450 KV HVDC Transmission Interconnection.	10-b-61		33-8164
Agreement between UNITIL Power Corp. and the. . . . . Company to sell 23 MW capacity and energy from Stony Brook Intermediate Combined Cycle Unit.	10-b-62		33-8164
Sales Agreement dated as of June 20, 1986,. . . . . . between the Company and Fitchburg Gas and Electric Light Company for sale of 10 MW capacity and energy from the Vermont Yankee plant.	10-b-64		33-8164
Firm Power and Energy Contract dated December 4,. . . 1987, between Hydro-Qubec and participating Vermont utilities, including the Company, for the purchase of firm power for up to thirty years.	10-b-68	Form 10-K 1992	(1-8291)
Firm Power Agreement dated as of October 26, 1987,. . between Ontario Hydro and Vermont Department of Public Service.	10-b-69	Form 10-K 1992	(1-8291)
Firm Power and Energy Contract dated as of. . . . . . February 23, 1987, between the Vermont Joint Owners of the Highgate facilities and Hydro-Quebec for up to 50 MW of capacity.	10-b-70	Form 10-K 1992	(1-8291)
Amendment to 10-b-70.	10-b-70(a)	Form 10-K 1992	
Interconnection Agreement dated as of . . . . February 23, 1987, between the Vermont Joint Owners of the Highgate facilities and Hydro-Qubec.	10-b-71	Form 10-K 1992	(1-8291)
Participation Agreement dated as of April 1, 1988,. . between Hydro-Qubec and participating Vermont . . . . June 1988 utilities, including the Company, implementing the purchase of firm power for up to 30 years under the Firm Power and Energy Contract dated December 4, 1987 (previously filed with the Company's Annual Report on Form 10-K for 1987, Exhibit Number 10-b-68).	10-b-72	Form 10-Q	(1-8291)
Restatement of the Participation Agreement filed. . . as Exhibit 10-b-72 on Form 10-Q for June 1988.	10-b-72(a)	Form 10-K 1988	(1-8291)
Agreement dated as of May 1, 1988, between.	10-b-73	Form 10-Q	

Rochester Gas and Electric Corporation and the. . . . Company, implementing the Company's purchase of up to 50 MW of electric capacity and associated energy.		September. 1988 (1-8291)
Firm Power and Energy Contract dated December 29, . . 1988, between Hydro-Qubec and participating Vermont utilities, including the Company, for the purchase of up to 54 MW of firm power and energy.	10-b-77	Form 10-K 1988 (1-8291)
Transmission Agreement dated December 23, 1988, . . . between the Company and Niagara Mohawk Power Corporation (Niagara Mohawk), for Niagara Mohawk to provide electric transmission to the Company from Rochester Gas and Electric and Central Hudson Gas and Electric.	10-b-78	Form 10-K 1988 (1-8291)
Sales Agreement dated May 24, 1989, between . . . . . the Town of Hardwick, Hardwick Electric Department. . and the Company for the Company to purchase all of the output of Hardwick's generation and transmission sources and to provide Hardwick with all-requirements energy and capacity except for that provided by the Vermont Department of Public Service or Federal Preference Power.	10-b-81	Form 10-Q June 1989 (1-8291)
Sales Agreement dated July 14, 1989, between. . . . . Northfield Electric Department and the Company. . . . for the Company to purchase all of the output of Northfield's generation and transmission sources and to provide Northfield with all-requirements energy and capacity except for that provided by the Vermont Department of Public Service or Federal Preference Power.	10-b-82	Form 10-Q June 1989 (1-8291)
Power Purchase and Sale Agreement between . . . . . . Morgan Stanley Capital Group Inc. and the Company	10-b-85	Form 10-K 1998 (1-8291)
Revolving Credit Agreement with KeyBank	10-b-86	Form 10-Q Sept. 20
Amendment to Fleet Revolving Credit Agreement	10-b-87	Form 10-Q Sept. 20
Energy East Power Purchase Option Agreement	10-b-88	Form 10-Q Sept.

2000 (1-8291)

MANAGEMENT CONTRACTS OR COMPENSATORY PLANS OR ARRANGEMENTS
REQUIRED TO BE FILED AS EXHIBITS TO THIS FORM 10-K
PURSUANT TO ITEM 14(C)., ALL UNDER SEC DOCKET 1-8291

Green Mountain Power Corporation Second Amended. . . . . . and Restated Deferred Compensation Plan for Directors.	10-d-1b	Form 10-K 1993
Green Mountain Power Corporation Second Amended. . . . . . and Restated Deferred Compensation Plan for Officers.	10-d-1c	Form 10-K 1993
Amendment No. 93-1 to the Amended and Restated . . . . . . Deferred Compensation Plan for Officers.	10-d-1d	Form 10-K 1993
Amendment No. 94-1 to the Amended and Restated . . . . . . Deferred Compensation Plan for Officers.	10-d-1e	Form 10-Q June 1994
Green Mountain Power Corporation Medical Expense . . . . . Reimbursement Plan.	10-d-2	Form 10-K 1991
Green Mountain Power Corporation Officer	10-d-4	Form 10-K 1991

Insurance Plan.		
Green Mountain Power Corporation Officers' . . . . Insurance Plan as amended.	10-d-4a	Form 10-K 1990
Green Mountain Power Corporation Officers' . . . . Supplemental Retirement Plan.	10-d-8	Form 10-K 1990
Green Mountain Power Corporation Compensation Program. . . for Officers and Key Management Personnel as amended August 4, 1997	10-d-15b	Form 10-K 1997
Severance Agreement with N. R. Brock	10-d-21	Form 10-K 1998
Severance Agreement with C. L. Dutton.	10-d-22	Form 10-K 1998
Severance Agreement with R. J. Griffin	10-d-23	Form 10-K 1998
Severance Agreement with M. H. Lipson.	10-d-25	Form 10-K 1998
Severance Agreement with C. T. Myotte.	10-d-26	Form 10-K 1998
Severance Agreement with W. S. Oakes	10-d-27	Form 10-K 1998
Severance Agreement with M. G. Powell.	10-d-28	Form 10-K 1998
Severance Agreement with S. C. Terry	10-d-29	Form 10-K 1998
Severance Agreement with J. H. Winer	10-d-30	Form 10-K 1998
Subsidiaries of the Registrant		21 Form 10-K
Consent of Arthur Andersen LLP	23-a-1	
Limited Power of Attorney		24

79

EXHIBIT 24

POWER OF ATTORNEY

We, the undersigned directors of Green Mountain Power Corporation, hereby severally constitute Christopher L. Dutton, Nancy R. Brock, and Robert J. Griffin, and each of them singly, our true and lawful attorney with full power of substitution, to sign for us and in our names in the capacities indicated below, the Annual Report on Form 10-K of Green Mountain Power Corporation for the fiscal year ended December 31, 2000, and generally to do all such things in our name and behalf in our capacities as directors to enable Green Mountain Power Corporation to comply with the provisions of the Securities Exchange Act of 1934, as amended, all requirements of the Securities and Exchange Commission, and all requirements of any other applicable law or regulation, hereby ratifying and confirming our signatures as they may be signed by our said attorney, to said Annual Report.

SIGNATURE	TITLE	DATE
_/s/ Christopher L. Dutton Christopher L. Dutton	President and Director (Principal Executive Officer)	February 5, 2001
_/s/ Thomas P. Salmon____ Thomas P. Salmon	Chairman of the Board	February 5, 2001
_/s/ Nordahl L. Brue_______ Nordahl L. Brue	Director	February 5, 2001
_/s/ William H. Bruett_____ William H. Bruett	Director	February 5, 2001

_/s/ Merrill O. Burns_____ Merrill O. Burns	Director	February 5, 2001
_/s/ Lorraine E. Chickering Lorraine E. Chickering	Director	February 5, 2001
_/s/ John V. Cleary________ John V. Cleary	Director	February 5, 2001
_/s/ David R. Coates________ David R. Coates	Director	February 5, 2001
_/s/ Euclid A. Irving______ Euclid A. Irving	Director	February 5, 2001

80

SIGNATURES

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

GREEN MOUNTAIN POWER CORPORATION

By: ____/s/ Christopher L. Dutton________
Christopher L. Dutton, President and Chief Executive Officer

Date: March 28, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

SIGNATURE	TITLE	DATE
__/s/ Christopher L. Dutton Christopher L. Dutton	President and Director (Principal Executive Officer)	March 28, 2001
_/s/Nancy R. Brock_______ Nancy R. Brock	Vice President, Treasurer and Chief Financial Officer (Principal Financial Officer)	March 28, 2001
/s/Robert J. Griffin_	Controller	March 28, 2001

Robert J. Griffin (Principal Accounting Officer)

*Thomas P. Salmon	Chairman of the Board
*Nordahl L. Brue)	
*William H. Bruett)	
*Merrill O. Burns)	
*David R. Coates)	
*Lorraine E. Chickering)	
*John V. Cleary)	Directors
*Euclid A. Irving)	

*By: _/s/ Christopher L. Dutton March 28, 2001

Christopher L. Dutton
(Attorney - in - Fact)