GREEN MOUNTAIN POWER CORP
Form 10-K
March 24, 2003

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, 2002

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_

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes _X_ No

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THE AGGREGATE MARKET VALUE OF THE VOTING STOCK HELD BY NON-AFFILIATES OF THE REGISTRANT AS OF MARCH 12, 2003, WAS APPROXIMATELY $100,939,195 BASED ON THE CLOSING PRICE OF $20.35 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 12, 2003, WAS 4,960,157

DOCUMENTS INCORPORATED BY REFERENCE

The Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 15, 2003, 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.

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Green Mountain Power Corporation

Form 10-K for the fiscal year ended December 31, 2002

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PART I

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 Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD and A"), in the 2002 Annual Report to Shareholders ("Annual Report"), and in the accompanying Notes to Consolidated Financial Statements ("Notes"), all included herein.

ITEM 1. BUSINESS

THE COMPANY

Green Mountain Power Corporation (the "Company" or "GMP") is a public utility operating company engaged in supplying electrical energy in the State of Vermont ("State" or "Vermont") in a territory with approximately one quarter of the State's population. We serve approximately 88,000 customers. The Company was incorporated under the laws of the State on April 7, 1893.

Our sources of revenue for the year ended December 31, 2002 were as follows:

* 26.8 percent from residential customers;
* 28.4 percent from small commercial and industrial customers;
* 17.7 percent from large commercial and industrial customers;
* 25.8 percent from sales to other utilities; and
* 1.3 percent from other sources.

See the Annual Report and MD and A for further information about revenues.

During 2002, our energy resources for retail and wholesale sales of electricity, excluding sales made pursuant to the contract with Morgan Stanley Capital Group, Inc. ("MS") discussed under MD and A-Power Contract Commitments, were obtained as follows:

* 40.8 percent from hydroelectric sources (32.8 percent Hydro Quebec, 5.0 percent Company-owned, 2.9 percent small power producers, and 0.1 percent New York Power Authority ("NYPA"));
* 34.9 percent from a nuclear generating source (the Entergy nuclear plant described below);
* 3.6 percent from wood;
* 2.5 percent from natural gas;
* 1.5 percent from oil; and
* 0.5 percent from wind.

The remaining 16.2 percent was purchased on a short-term basis from other utilities through the Independent System Operator of New England ("ISO" or "ISO New England"), formerly the New England Power Pool ("NEPOOL").

In 2002, we purchased 90.7 percent of our energy resources to satisfy our retail and wholesale sales of electricity, including energy purchased from Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VY") and under other long-term purchase arrangements, but excluding purchases for resale under the MS contract. See Note K of Notes.

A major source of the Company's power supply is our entitlement to a share of the power generated by the 531 megawatt (MW) nuclear generating plant owned and operated by Entergy Vermont Yankee Nuclear Corporation ("Entergy"). We have an 18.99 percent equity interest in Vermont Yankee, which has a long-term power supply contract with Entergy, that entitles us to 20 percent of plant output through 2012 For further 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 deregulated wholesale energy 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 such high usage periods such as 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.

Our 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 and towns of Montpelier, Barre, South Burlington, Vergennes, Williston, Shelburne, and Winooski, as well as the Village of Essex Junction and a number of smaller 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 Entergy nuclear plant is located), Bellows Falls, White River Junction, Wilder, Wilmington and Dover. The Company's right to distribute electrical service in its service territory is the utility's most important asset. 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, tourism (particularly fall and winter recreation), and dairy and general farming.

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,

	2,002	2001	2000	1999
Total capability (MW)	406.9	408.0	411.1	39
Net system peak	342.0	341.2	323.5	31
Reserve (MW).	64.9	66.8	87.6	7
Reserve % of peak	19.0%	19.6%	27.1%	2
Net Production (MWH**)				
Hydro	901,998	951,146	1,053,223	1,095,
Wind.	11,458	12,135	12,246	7,
Nuclear	771,781	736,420	803,303	731,
Conventional steam.	2,431,115	2,670,249	2,704,427	2,328,
Internal combustion	4,090	18,291	35,699	12,
Combined cycle.	81,362	72,653	73,433	99,
Total production.	4,201,804	4,460,894	4,682,331	4,275,
Less non-firm sales to other utilities.	2,104,172	2,365,809	2,573,576	2,152,
Production for firm sales	2,097,632	2,095,085	2,108,755	2,122,
Less firm sales and lease transmissions.	1,951,959	1,956,232	1,954,898	1,920,
Losses and company use (MWH).	145,673	138,853	153,857	202,
Losses as a % of total production	3.47%	3.11%	3.29%	4
System load factor (***).	70.0%	70.1%	74.2%	7
Net Production (% of Total)				

Hydro	21.5%	21.3%	22.5%	2
Wind	0.3%	0.3%	0.3%	
Nuclear	18.3%	16.5%	17.1%	1
Conventional steam	57.9%	59.9%	57.8%	5
Internal combustion	0.1%	0.4%	0.8%	
Combined cycle	1.9%	1.6%	1.6%	
Total	100.0%	100.0%	100.0%	10
Sales and Lease Transmissions(MWH)				
Residential - GMPC	553,294	549,151	558,682	544,
Commercial & industrial - small	723,642	718,969	704,126	688,
Commercial & industrial - large	661,480	683,004	683,296	664,
Other	9,773	2,030	6,713	3,
Total retail sales and lease transmissions	1,948,189	1,953,154	1,952,817	1,900,
Sales to Municipals & Cooperatives (Rate W)	3,770	3,078	2,081	20,
Total Requirements Sales	1,951,959	1,956,232	1,954,898	1,920,
Other Sales for Resale	2,104,172	2,365,809	2,573,576	2,152,
Total sales and lease transmissions(MWH)	4,056,131	4,322,041	4,528,474	4,073,
Average Number of Electric Customers				
Residential	73,861	73,249	72,424	71,
Commercial and industrial small	13,173	12,984	12,746	12,
Commercial and industrial large	21	22	23	
Other	65	65	65	
Total	87,120	86,320	85,258	84,
Average Revenue Per KWH (Cents)				
Residential including lease revenues	12.96	13.33	12.50	12
Commercial & industrial - small	10.35	10.83	10.00	9
Commercial & industrial - large	7.28	7.69	6.51	6
Total retail including lease	10.09	10.44	9.52	9
Average Use and Revenue Per Residential Customer				
KWh's including lease transmissions	7,491	7,497	7,717	7,
Revenues including lease revenues	$ 971	$ 999	$ 965	$

(*) 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.

STATE AND FEDERAL REGULATION

General. The Company is subject to the regulatory authority of the Vermont Public Service Board ("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, 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. Political or social organizations that represent certain classes of customers, neighbors of our properties, or other persons or entities may petition the VPSB to be granted intervener status in such proceedings.

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 International Business Machines Corporation ("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 1.0 percent of our operating revenues for 2002.

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 percent of our operating revenues for 2002.

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 FERC Order 889, we have 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 FERC Order 889. Our 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 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 hydroelectric projects we own:

	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	expired August 31, 2001, renewal pending

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 Waterbury reservoir was drained in 2001 to prepare for repairs to the dam by the State, presently estimated for completion in 2004. Once repairs are complete, we expect the project to be relicensed for a 30 year term and we do not have any competition for the Waterbury license.

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

RETAIL RATE CASES- The Company reached a final settlement agreement with the Department in its 1998 rate case during November 2000. The final settlement agreement contained the following provisions:

* The Company received 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 were set at levels that recover the Company's Hydro Quebec VJO contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;
* The Company agreed 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 in 2000 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 were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2002 and 2003;
* The Company agreed 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;
* The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in our 1997 rate case; and
* The Company agreed to an earnings limitation for its electric operations in an amount equal to its allowed rate of return of 11.25 percent, with amounts earned over the limit being used to write off regulatory assets.

On January 23, 2001, the VPSB approved our settlement with the Department, with two additional conditions:
* The Company and customers shall 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, adjusted for inflation; and
* The Company's further investment in non-utility operations is restricted.

The Company earned approximately $4.4 million less than its allowed rate of return during 2002 before including in earnings deferred revenues in the same amount. The Company earned approximately $30,000 in excess of its allowed rate of return during 2001 before writing off regulatory assets in the same amount.

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

SINGLE CUSTOMER DEPENDENCE

The Company had one major retail customer, IBM, metered at two locations that accounted for 12.8 percent, 13.5 percent, and 12.4 percent of total operating revenues, and 17.3 percent, 19.2 percent and 16.5 percent of the Company's retail operating revenues in 2002, 2001 and 2000, respectively. IBM's percent of total revenues and MWh sales in 2001 increased due to a rate increase and a decrease in total operating revenues as a result of decreased sales for resale pursuant to the MS contract, which is discussed in greater detail in Item

7 of MD and A-Power Contract Commitments. No other retail customer accounted for more than 1.0 percent of our revenue during the past three years.

IBM reduced its Vermont workforce by 1,500 during 2002, to a level of approximately 7,000 employees. If future significant losses in electricity sales to IBM were to occur, the Company's earnings could be impacted adversely. If earnings were materially reduced as a result of lower retail sales, we would seek a retail rate increase from the VPSB. The Company is not aware of any plans by IBM to further reduce production at its Vermont facility. We currently estimate, based on a number of projected variables, the retail rate increase required from all retail customers by a hypothetical shutdown of the IBM facility to be in the range of five to ten percent, inclusive of projected declines in sales to residential and commercial customers. See Item 7. MD and A-Results of Operations, Operating Revenues and MWh, and Note A of Notes.

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 a municipal public utility.

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase the Bellows Falls hydroelectric facility from a third party, and the associated distribution plant owned by the Company within the town. In March 2002, voters in Rockingham approved an article authorizing Rockingham to create a municipal utility by acting to acquire a municipal plant, which would include the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that neither our remaining customers nor our shareholders effectively subsidize a Rockingham municipal 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 to residential and farm customers and the Department could sell only power that it had purchased from the Niagara and St. Lawrence projects operated by the New York Power Authority.

Under the 1987 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. Since 1987, 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. Alternate forms of performance-based regulation currently appear as possible intermediate steps towards deregulation. For further information regarding Competition and

Restructuring, See Item 7. MD and A - Future Outlook.

CONSTRUCTION AND CAPITAL REQUIREMENTS

Our capital expenditures for 2000 through 2002 and projected for 2003 are set forth in Item 7. MD and A - 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 2000-2002, internally generated funds, after payment of dividends, provided approximately 68 percent of our total capital requirements for construction, sinking fund obligations and other requirements. Internally generated funds provided 49 percent of such requirements for 2002. We anticipate that for 2003, internally generated funds will provide approximately 71 percent of our 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.

POWER RESOURCES

On February 11, 1999, the Company entered into a contract with Morgan Stanley Capital Group, Inc. ("MS"). In August 2002, the MS contract was modified and extended to December 31, 2006. The contract provides us a means of managing price risks associated with changing fossil fuel prices. For additional information on the MS contract, see Note K of Notes.

We generated, purchased or transmitted 2,210,721 MWh of energy for retail and requirements wholesale customers for the twelve months ended December 31, 2002. The corresponding maximum one-hour integrated demand during that period was 342.0 MW on August 15, 2002. This compares to the previous all-time peak of 341.2 MW on August 9, 2001. 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.

Net Electricity Generated and Purchased and Capacity at Peak

	Generated and Purchased During year Ended 12/31/2002 MWH	percent	Capacity At time of of annual peak KW	percent
Wholly-owned plants:				
Hydro	110,797	5.0%	32,870	8.9%
Diesel and Gas Turbine.	4,090	0.2%	50,623	13.6%
Wind.	11,458	0.5%	480	0.1%
Jointly-owned plants:				
Wyman #4.	3,687	0.2%	6,968	1.9%
Stony Brook I	55,595	2.5%	27,113	7.3%
McNeil.	19,832	0.9%	6,443	1.7%
Long Term Purchases:				
Vermont Yankee Nuclear/Entergy.	771,781	34.9%	100,554	27.1%
Hydro-Quebec.	724,708	32.8%	114,174	30.8%
Stony Brook I	25,767	1.2%	12,382	3.3%

Other:				
Small Power Producers	123,996	5.6%	19,286	5.2%
NEPOOL and Short-term purchases	359,009	16.2%	400	0.1%
Net Own Load.	2,210,720	100.0%	371,293	100.0%

Vermont Yankee.

On July 31, 2002, Vermont Yankee completed the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy"). In addition to the sale of the generating plant, the transaction calls for Entergy, through its power contract with VY, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of our projected energy requirements. The Company continues to own approximately 19 percent of the common stock of VY. Our benefits of the plant sale and the VY power contract with Entergy include:

VY receives cash approximately equal to the book value of the plant assets, removing the potential for stranded costs associated with the plant.

VY and its owners will no longer bear operating risks associated with running the plant.

VY and its owners will no longer bear the risks associated with the eventual decommissioning of the plant.

Prices under the Power Purchase Agreement between VY and Entergy (the "PPA") range from $39 to $45 per megawatt-hour for the period beginning January 2003, substantially lower than the forecasted cost of continued ownership and operation by VY. Contract prices ranged from $49 to $55 for 2002, higher than the forecasted cost of continued ownership for 2002.

The PPA calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, contract prices are not adjusted upward.
The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the Entergy plant.
The VY plant had fuel rods that required repair during May 2002, a maintenance requirement that is not unique to VY. VY closed the plant for a twelve-day period, beginning on May 11, 2002, to repair the rods. Our cost for the repair, including incremental replacement energy costs, was approximately $2.0 million.
The Company received an accounting order from the VPSB on August 2, 2002, allowing it to defer the additional costs related to the outage, and believes that such amounts are probable of future recovery.
Our ownership share of VY has increased from approximately 17.9 percent last year to approximately 19.0 percent currently, due to VY's purchase of certain minority shareholders' interests. VY's primary role consists of administering its power supply contract with Entergy and its contracts with VY's present sponsors. Our entitlement to energy produced by the Entergy nuclear plant has increased from approximately 18 percent to 20 percent of plant production through a series of transactions in connection with the sale of the plant to Entergy.

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

During periods when Vermont Yankee power is unavailable, we occasionally 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. 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.

The Entergy nuclear plant's current operating license expires March 2012.

During the year ended December 31, 2002, we used 771,781 MWh of Vermont Yankee energy representing 34.9 percent of the net electricity generated and purchased ("net power supply") by the Company. The average cost of Vermont Yankee electricity in 2002 was $0.045 per kWh. Vermont Yankee's annual capacity factor for 2002 was 88.7 percent compared with 91.2 percent for 2001, 99.2 percent in 2000, and 90.9 percent in 1999.

See Note B and Note K of Notes for additional information.

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 percent of the total power-supply benefits associated with the NEPOOL/Hydro Quebec interconnection. The Company, in turn, receives approximately 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, other NEPOOL members and Hydro Quebec provided for the construction of the second phase ("Phase II") of the interconnection between New England Electric System and 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 percent 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, 2002, the present value of the Company's obligation was approximately $5,287,000. The Company's projected future minimum payments under the Phase II support agreements are approximately $407,000 for each of the years 2003-2007 and an aggregate of $3,253,000 for the years 2008-2015.

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 percent 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, 2002, the capital structure of such corporations was approximately 43 percent common equity and 57 percent long-term debt. See Note B and Note J of Notes.

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 Expenses.

Hydro Quebec Power Supply Contracts. We have several power purchase 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. from Hydro Quebec. 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 2001 resulted in an increase of approximately $7.6 million of power supply expenses to meet contractual obligations under the Company's December 1997 arrangement (the "9701 arrangement", or "9701") with Hydro Quebec. See Item 7. MD and A - Power Supply Expenses, and Note K of Notes.

During 2002, we used 432,171 MWh under Schedule B, and 292,537 MWh under Schedule C3 of the Hydro Quebec arrangements representing 32.8 percent of our net power supply. The average cost of Hydro Quebec electricity in 2002 was approximately $0.066 per kWh.

NEPOOL and 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 purchase or sell 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.

NEPOOL is the New England Power Pool whereby participants are able to buy and sell wholesale power, through the regional independent system operator, known as ISO New England for the New England region, to meet current demand conditions within New England's transmission system, and within each participant's own distribution system. The Company uses power purchased from NEPOOL and other short-term opportunity market purchases to fulfill occasional changes in the demand and supply matrix. During 2002, the Company purchased 359,009 MWh representing 16.2 percent of the Company's net power supply at an average cost of $0.05 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. In October 1997, we entered into a Joint Ownership Agreement with MMWEC, whereby we acquired an 8.8 percent 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 2002, we used 81,362 MWh from this plant representing 3.7 percent of our net power supply at an average cost of $0.06 per kWh. See Note I of Notes.

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 percent (7.1 MW) in the Wyman #4 unit, which began commercial operation in December 1978.

During 2002, we used 3,687 MWh from this unit representing 0.2 percent of our net power supply at an average cost of $0.091 per kWh, based only on operation, maintenance, and fuel costs incurred during 2002. See Note I of Notes.

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 percent 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 2002, we used 19,832 MWh from this unit representing 0.9 percent of our net power supply at an average cost of $0.049 per kWh, based only on operation, maintenance, and fuel costs incurred during 2002. See Note I of Notes.

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 ratemaking 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 2002 was approximately 33.5 percent or 50.2 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 excess capacity in the region has eliminated the need for and value of additional qualifying facilities.

In 2002, through our direct contracts and VEPPI, we purchased 123,996 MWh of qualifying facilities production representing 5.6 percent of our net power supply at an average cost of $0.116 per kWh.

Company Hydroelectric Power. We wholly own and operate eight hydroelectric generating facilities located on river systems within our service area, the largest of which has a generating output of 7.8 MW.

In 2002, Company owned hydroelectric plants provided 110,797 MWh of pollution free energy, representing 5.0 percent of our net power supply at an average cost of $0.043 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.

Fuel. During 2002, our retail and requirements wholesale sales were provided by the following fuel sources:

* 40.8 percent from hydroelectric sources (32.8 percent Hydro Quebec, 5.0 percent Company-owned, 2.9 percent small power producers, and 0.1 percent NYPA);
* 34.9 percent from a nuclear generating source (the Entergy nuclear plant);
* 3.6 percent from wood;
* 2.5 percent from natural gas;
* 1.5 percent from oil;
* 0.5 percent from wind; and
* 16.2 percent purchased on a short-term basis from other utilities through the ISO.

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 2002, however, we are experiencing some difficulty during 2003 as a result of extended cold weather that has affected fuel deliveriesNone of the utilities from which we expect to purchase oil- or gas-fired capacity in 2003 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 257,268 tons of wood chips and mill residue, 54,827 gallons of fuel oil, and 37,869 million cubic feet of natural gas in 2002. The McNeil plant, assuming any needed regulatory approvals are obtained, is forecasting 2003 consumption of wood chips to be 300,000 tons, fuel oil of 70,000 gallons and natural gas consumption of 36,000 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 Department of Energy ("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 2002, the project provided pollution free 11,458 MWh, representing 0.5 percent of the Company's net power supply at an approximate average cost of $0.04 per kWh, based only on maintenance costs.

SEGMENT INFORMATION

Financial information about the Company's primary industry segment, the electric utility, is presented in Item 6, Selected Financial Data, and in the Annual Report and Notes included herein.

The Company has sold or disposed of substantially all of the operations and assets of Northern Water Resources, Inc. ("NWR"), formerly known as Mountain Energy, Inc., classified as discontinued operations in 1999. Industry segment information relating to the Company's discontinued operations is presented in Note L of Notes.

SEASONAL NATURE OF BUSINESS

Winter recreational activities, longer hours of darkness and heating loads from cold weather historically caused our average peak electric sales to occur in December, January or February. Summer air conditioning loads have increased in recent years as a result of steady economic growth in our service territory. As a result, our heaviest load in 2002, 342.0 MW, occurred on August 15, 2002.

Under NEPOOL market rules implemented in May 1999, the cost basis that had supported the Company's previous seasonally differentiated rate design was eliminated, making a seasonal rate structure no longer appropriate. The elimination of the seasonal rate structure in all classes of service effective April 2001 was approved by the VPSB in January 2001.

EMPLOYEES

As of December 31, 2002, the Company had 194 employees, exclusive of temporary employees. The Company considers its relations with employees to be excellent.

ENERGY EFFICIENCY

In 2002, GMP did not offer its own energy efficiency programs. Energy efficiency services were provided to GMP's customers by a statewide Energy Efficiency Utility ("EEU") known as "Efficiency Vermont", created by the VPSB in 1999. The EEU is funded by a separate energy efficiency charge that appears as a line item on each customer bill. In 2002, the charge was 2.0777 percent of each customer's total electric bill. Some charges, such as late fees and outdoor lighting, are excluded. The funds we collect are remitted to a fiscal agent representing the State of Vermont. From 1992 through 1999, the Company's efficiency programs achieved a cumulative annual saving of 89,000 megawatthours, saving approximately $7.9 million per year for our customers.

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 1,904 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, 2002, approximately 1,657 of the Company's largest customers, comprising 52 percent of retail revenues, received 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 eliminated seasonal rate differentials effective April 2001.

DISPATCHABLE AND INTERRUPTIBLE SERVICE CONTRACTS

In 2002, we had 27 dispatchable power contracts: 20 contracts were year-round, while the 5 seasonal contracts included 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.

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 Barge Canal site and other environmental matters, see Item 7. MD and A- Environmental Matters, and Note I of Notes.

UNREGULATED BUSINESSES

In 1999, Green Mountain Resources, Inc. sold its remaining interest in Green Mountain Energy Resources. During 1999, the Company discontinued operations of Northern Water Resources, Inc.("NWR"), a subsidiary of the Company that invested in wastewater, energy efficiency and generation businesses. NWR's remaining assets include an interest in a wind generation facility in California, a note from a hydroelectric facility in New Hampshire, and a wastewater businessin the process of completing dissolution. For information regarding our remaining unregulated businesses, see Item 7a. MD and A - Unregulated Businesses.

EXECUTIVE OFFICERS

The names, ages, and positions of our Executive Officers, in alphabetical order, as of March 15, 2003 are:

Christopher L. Dutton 54

President and 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, CPA 46

Treasurer since February 2002. Controller since October 1996. Manager of General Accounting from 1990 to 1996.

Walter S. Oakes 56

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 42

Senior Vice President-Chief Operating Officer since April 2001. 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, Inc., a human resources management firm, from January 1997 to March 1998.

Donald J. Rendall, 47

Vice President, General Counsel and Corporate Secretary since July 2002, March 2002, and December 2002, respectively. Prior to joining the Company, he was a principal in the Burlington, Vermont law firm of Sheehey, Furlong, Rendall & Behm, P.C. from 1988 to February 2002.

Stephen C. Terry 60

Senior Vice President-Corporate 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.

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.

Additional information regarding compensation, beneficial ownership of the Company's stock, members of the board of directors, and other information is presented in the Company's Proxy Statement to Shareholders dated March 28, 2003, and is hereby incorporated by reference.

AVAILABLE INFORMATION

Our Internet website address is: www.Greenmountainpower.biz. We make available free of charge through the website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. The information on our website is not, and shall not be deemed to be, a part of this report or incorporated into any other filings we make with the SEC.

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:

* 18.99 percent of the outstanding common stock of Vermont Yankee and, through its contract with Entergy, we are entitled to 20.0 percent (106.2 MW of a total 531 MW) of the capacity of the Entergy Nuclear Vermont Yankee plant,
* 1.1 percent (7.1 MW of a total 620 MW) joint-ownership share of the Wyman #4 plant located in Maine,
* 8.8 percent (31.0 MW of a total 352 MW) joint-ownership share of the Stony Brook I intermediate units located in Massachusetts, and
* 11.0 percent (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, 2002, approximately 2 miles of 115 kV transmission lines, 10 miles of 69 kV transmission lines, 5 miles of 44 kV transmission lines, 187 miles of 34.5 kV transmission lines, and 2 miles of 13.8 kV transmission lines. Our distribution system included approximately 2,340 miles of overhead lines of 2.4 to 34.5 kV and 455 miles of underground cable of 2.4 to 34.5 kV. At such date, we owned approximately 115,000 kV of substation transformer capacity in transmission substations and 590,000 kV of substation transformer capacity in distribution substations and approximately 872,000 kV of transformers for step-down from distribution to customer use.

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

We also own 28.4 percent of the common stock and 30 percent of the preferred stock of VELCO, which operates a high-voltage transmission system interconnecting electric utilities in the State of Vermont.

PROPERTY OWNERSHIP

Our 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. See Note F, Long-Term Debt, for more information concerning our First Mortgage Bonds.

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	
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	(1)
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	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				162.5	

(1) Reservoir has been drained, dam awaiting repairs by the State of Vermont.
(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.

CORPORATE HEADQUARTERS

Our headquarters and main service center are located in Colchester Vermont, one of the most rapidly growing areas of our service territory. The Company terminated an operating lease for its former 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 its two service centers.

ITEM 3. LEGAL PROCEEDINGS

The Company is not involved in any material litigation at the present time. See the discussion under Item 7. MD and A - Environmental Matters, Rates, and Note I of Notes.

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 our 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 2001 and 2002:

	HIGH	LOW
	2001	
First Quarter.	$19.50	$11.06
Second Quarter	16.65	14.88
Third Quarter.	17.74	15.56
Fourth Quarter	18.85	15.90
	2002	
First Quarter.	$19.00	$17.00
Second Quarter	19.50	17.54
Third Quarter.	18.25	15.75
Fourth Quarter	21.08	15.89

The number of common stockholders of record as of March 12, 2003 was approximately 5,190.

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2001	$ 0.1375	$ 0.1375	$ 0.1375	$ 0.1375
2002	$ 0.1375	$ 0.1375	$ 0.1375	$ 0.1900

Dividend Policy. The annual dividend rate was increased from $0.55 per share to $0.76 per share beginning with the $0.19 quarterly dividend declared in December 2002. The Company intends to increase the dividend in a measured consistent manner until the payout ratio falls between 50 percent and 60 percent of anticipated earnings. We believe this payout ratio to be consistent with that of other utilities having similar risk profiles.

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

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. Our 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, the Board of Directors would consider whether the current dividend level is appropriate. See Item 7. MD and A - Liquidity and Capital Resources-Dividend Policy, Future Outlook, Competition and Restructuring, and Note C of Notes for a discussion of dividend restrictions.

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ITEM 6. SELECTED FINANCIAL DATA

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, In thousands, except per share data

	2002	2001	2
Operating Revenues	$274,608	$283,464	$27
Operating Expenses	259,528	267,005	27
Operating Income	15,080	16,459	
Other Income			
AFUDC - equity	233	210	
Other	2,252	2,163	
Total other income	2,485	2,373	
Interest Charges			
AFUDC - borrowed	(103)	(188)	
Other	6,273	7,227	
Total interest charges	6,170	7,039	
Net Income (Loss) from continuing operations before preferred dividends	11,395	11,793	
Net Income (Loss) from discontinued operations, including provisions for loss on disposal	99	(182)	(
Dividends on Preferred Stock	96	933	
Net Income (Loss)Applicable to Common Stock	$ 11,398	$ 10,678	$ (
Common Stock Data			
Basic earnings per share-continuing operations	$ 2.02	$ 1.93	$
Basic earnings per share-discontinued operations	0.02	(0.03)	
Basic earnings per share	$ 2.04	$ 1.90	$
Diluted earnings (loss) per share from discontinued operations	$ 1.96	$ 1.88	$
Diluted earnings (loss) per share from continuing operations	0.02	(0.03)	
Diluted earnings (loss) per share	$ 1.98	$ 1.85	$
Cash dividends declared per share	$ 0.60	$ 0.55	$
Weighted average shares outstanding-basic	5,592	5,592	
Weighted average share equivalents outstanding-diluted	5,756	5,756	

FINANCIAL CONDITION AS OF DECEMBER 31

In thousands

	2002	2001	2000	1999	1998
ASSETS					
Utility Plant, Net	$203,529	$196,858	$194,672	$192,896	$195,556
Other Investments	21,552	20,945	20,730	20,665	20,678
Current Assets	31,432	36,183	53,652	33,238	35,700
Deferred Charges	51,594	72,468	46,036	41,853	35,576
Non-Utility Assets	995	1,075	1,518	11,099	27,314

Total Assets.	$309,102	$327,529	$316,608	$299,751	$314,824
	========	========	========	========	========
CAPITALIZATION AND LIABILITIES					
Common Stock Equity	$ 91,722	$101,277	$ 92,044	$100,645	$106,755
Redeemable Cumulative Preferred Stock .	55	12,560	12,795	14,435	16,085
Long-Term Debt, Less Current Maturities	93,000	74,400	72,100	81,800	88,500
Capital Lease Obligation.	5,287	5,959	6,449	7,038	7,696
Current Liabilities	38,491	38,841	68,109	36,708	28,825
Deferred Credits and Other.	78,606	92,791	61,794	59,125	59,889
Non-Utility Liabilities	1,941	1,701	3,317	-	7,074
Total Capitalization and Liabilities. .	$309,102	$327,529	$316,608	$299,751	$314,824
	========	========	========	========	========

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.

Our critical accounting policies are discussed in Item 7a, "Quantitative And Qualitative Disclosures About Market Risk, And Other Factors", and in Item 8, Note 1, "Significant Accounting Policies". Management believes the most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate and the manner in which we account for certain power supply arrangements that qualify as derivatives. These accounting policies, among others, affect the Company's more significant judgments and estimates used in the preparation of its consolidated financial statements.

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 the captions "Power Contract Commitments", "Future Outlook," "Transmission Expenses," "Environmental Matters," "Rates, "and "Liquidity and Capital Resources," in this Management Discussion and Analysis and include:

* regulatory and judicial decisions or legislation;
* weather;
* changes in regional market and transmission rules;
* energy supply and demand and pricing;
* contractual commitments;
* availability, terms, and use of capital;
* general economic and business environment;
* changes in technology;
* 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

The Company reported consolidated earnings of $1.98 per share of common stock, diluted, in 2002, compared to earnings of $1.85 per share in 2001 and a loss of $1.25 per share in 2000. The 2002 earnings represent a consolidated return on average common equity of 11.03 percent, and a return on regulated operations of 11.25 percent. The consolidated return on average common equity was 11.02 percent in 2001 and negative 7.1 percent in 2000. Income from continuing operations was $1.96 per share, diluted, in 2002, compared with $1.88 per share, diluted, in 2001, and a loss of $0.06 per share in 2000. The Company's subsidiary Northern Water Resources, Inc. ("NWR"), classified as discontinued in 1999, earned $0.02 per share in 2002 compared with a loss of $0.03 per share in 2001, and a loss of $1.19 per share in 2000. A significant portion of NWR's assets, which consisted of energy generation and efficiency investments and wastewater treatment projects, have been sold, or otherwise disposed. NWR's 2002 earnings resulted primarily from an adjustment to a reserve for warranty claims.

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 granted the Company an immediate 3.42 percent rate increase, and allowed full recovery of power supply costs under the Hydro Quebec Vermont Joint Owners ("VJO") contract(the "VJO Contract"). The Settlement Order paved the way for restoration of the Company's first mortgage bond credit rating to investment grade status in 2001 (See "Rates-Retail Rate Cases" and "Liquidity and Capital Resources" in this section) and enabled the Company to earn its allowed rate of return of 11.25 percent on regulated operations during 2002 and 2001.

The improvement in earnings from continuing operations in 2002 compared with 2001 resulted from reductions in the Company's cost of capital and other operating expenses, partially offset by increases in maintenance and transmission expenses and lower gross margins on the Company's sales. Lower capital costs resulted from reduced interest rates and average debt levels, which caused 2002 interest expense to decline by $0.9 million compared to 2001, and the redemption of preferred stock which reduced 2002 preferred stock dividends $0.8 million compared with 2001. Lower gross margins resulted from an increase in power supply costs to serve retail customers, that was only partially offset by recognition of $4.4 million in revenue deferred in 2001 under the Settlement Order.

The improvement in earnings from continuing operations in 2001, compared with 2000, resulted primarily from several factors, including:

* 2001 power supply costs were $10.5 million lower than during 2000, principally due to decreased costs associated with the management of the Company's long-term power supply sale commitments to Hydro Quebec, and a decrease in lower margin wholesale sales of electricity;
* the 3.42 percent retail rate increase under the Settlement Order resulted in an increase of $9.1 million in 2001 retail operating revenues; and
* the write-off in 2000 of $3.2 million, or $0.35 per share, in regulatory litigation costs.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK, AND OTHER RISK FACTORS.

POWER SUPPLY RISK.

Our material power supply contracts and arrangements are principally with Hydro Quebec, MS and Vermont Yankee Nuclear Power Corporation. At December 31, 2002, more than 90 percent of our estimated load requirements through 2006 are expected to be met by these contracts and arrangements, and by our own generation and other power supply resources, which reduces the Company's exposure to market prices.

A primary factor affecting future operating results is the volatility of the wholesale electricity market. Restructuring of the wholesale market for electricity has brought increased price volatility to our power supply markets. Inherent in our market risk sensitive instruments and positions are the potential losses that may result from adverse changes in our commodity prices.

One objective of the Company's risk management program is to stabilize cash flow and earnings by minimizing power supply risks. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and transmission congestion rights with counter-parties that have at least investment grade ratings. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions.

The Company has a contract with Morgan Stanley Capital Group, Inc. ("MS"), which is used to hedge against increases in fossil fuel prices. MS purchases the majority of the Company's power supply resources at index prices for fossil fuel resources or specified prices for contracted resources and then sells to us at a fixed rate to serve pre-established load requirements. This contract, along with other power supply commitments, allows the Company 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 Statement of Financial Accounting Standards No. 133 ("SFAS 133") and is effective through December 31, 2006. Management's estimate of the fair value of the future net benefit of this arrangement at December 31, 2002 is approximately $8.8 million. Assumptions used to calculate the future net benefit using the Blacks option valuation model include a risk-free interest rate of 3.4 percent, volatility equivalent to a weighted average from NEPOOL, which varies from 32 percent in the first year to 29 percent in the fourth year, locked in forward commitment prices for 2003, with an estimated forward market price of approximately $43 per MWh for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Actual results may differ materially from the table below.

We currently have an arrangement that grants Hydro Quebec an option ("9701") to call power at prices that are expected to be below estimated future market rates. This arrangement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for this arrangement at December 31, 2002 is approximately $27.2 million. We sometimes use futures contracts to hedge forecasted sales of electric power under 9701.

A sensitivity analysis has been prepared to estimate exposure to the market price risk of 9701, using the Black-Scholes model, over the next 13 years. Assumptions used within the model include a risk-free interest rate of 5.02 percent, volatility equivalent to the weighted average from NEPOOL, which varies from 48 percent in the first year to 26 percent in year 13, locked in forward commitment prices for 2003, and an average of approximately 59,326 MWh per year, with an estimated forward market price of $59.81 per MWh for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Quoted forward market prices for monthly peak power rates are not currently available beyond 2004. The table below presents market risk estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in prices, which for the Company's derivatives discussed above totals approximately $0.9 million. Actual results may differ materially from the table below. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are not recognized in earnings until the derivative positions are settled.

Commodity Price Risk	At December 31, 2002	
	Fair Value	Market Risk
	(in thousands)	
Net short position	$ 18,405	$ 880

REGULATORY RISK- There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont. However, if Vermont adopted such restructuring, the major risk factors for the Company that may arise 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 by the Company of its stranded costs of between $203 million and $224 million over the life of the contracts. 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 in Vermont have been based on a utility's cost of service. As a result, Vermont electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards No. 71 ("SFAS 71"), Accounting for the Effects of Certain Types of Regulation, allows regulated entities, including the Company, 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.

Regulatory assets represent incurred costs that have been deferred because the Company has concluded that they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs. The Company's last retail rate case was filed during 1998. Since that time a material amount of expenditures have been deferred as regulatory assets pending consideration by the VPSB in a future retail rate proceeding. These regulatory assets have been judged as probable of recovery by management. The most significant regulatory assets that are not being currently amortized in rates, or are being amortized at amounts that could materially differ from future expenditure levels, include:

Regulatory assets

	At December 31, 2002	2001
(in thousands)		
Pine Street Barge Canal. . .	13,019	12,425
Unscheduled VY outage costs.	2,002	-
Demand Side Management . . .	6,434	6,961
Storm damages.	1,905	2,169
Tree Trimming.	905	905

Regulatory assets.	$24,265	$22,460
	=======	=======

Management's conclusion that these assets are probable of recovery is based on a variety of factors, including benefits to customers, consistency with past regulatory treatment, materiality of costs relative to normal cost levels, similar rate case decisions in other jurisdictions applying cost of service ratemaking principles, and opportunities to recover these costs over extended periods of time. If the VPSB were to disallow any of these costs, the result would be a pretax charge to current earnings in the amount of the disallowance.

The Company currently complies with the provisions of SFAS 71. If the Company had determined that it no longer met the criteria for following SFAS 71, at December 31, 2002 the accounting impact would have been an extraordinary non-cash charge to operations of $51.6 million. Factors that could give rise to the discontinuance of SFAS 71 include:

* deregulation;
* a change in the regulators' 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.

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. However, we believe that the continued application of SFAS 71 is appropriate at this time.

We cannot predict whether restructuring legislation, if 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.

PENSION RISK-Other critical accounting policies involve the non-contributory defined benefit pension and postretirement health care benefit plans of the Company. The reported costs of these plans are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension and postretirement health care costs are impacted by actual employee demographics, the level of Company contributions to the plans, earnings on plan assets, and health care cost trends (postretirement health care plan only).

The Company's pension and postretirement health care benefit plan assets consist of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may result in increased or decreased costs in future periods. Changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded defined benefit plan costs. For example, the Company in 2003 expects to reduce the expected return on its plan assets by 50 basis points to 8.5 percent, resulting in a $210,000 increase in plan expense. See Note H for further information.

As a result of our plan asset experience, at December 31, 2002, the Company was required to recognize an additional minimum liability of $2.4 million, net of applicable income taxes, as prescribed by SFAS 87. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income ("OCI"), and did not affect net income for 2002. The charge to OCI may be restored through common equity in future periods to the extent fair value of trust assets exceeded the accumulated benefit obligation. Current changes to plan assumptions, along with plan losses experienced during 2002, are expected to result in increased pension and postretirement health benefit expenses of approximately $0.6 million and $0.5 million, respectively, for 2003 compared with 2002.

UNREGULATED BUSINESSES

Most of the assets of NWR, which invested in energy generation, energy efficiency and wastewater treatment projects, have been sold. NWR earned $0.1 million in 2002, compared with a loss of approximately $0.2 million in 2001, and a loss of $6.5 million in 2000. The 2002 earnings and 2001 loss resulted primarily from provisions to recognize adjustments to liability estimates under warranties for past equipment sales.

Risk factors associated with the discontinuation of NWR 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 NWR, have commenced or threatened litigation against Micronair. The ultimate loss remains subject to the disposition of remaining NWR assets and liabilities, and could exceed the amounts recorded.

The Company's unregulated rental water heater business earned $0.3 million in 2002, essentially unchanged from the prior two years.

RESULTS OF OPERATIONS

OPERATING REVENUES AND MWH SALES-Operating revenues and megawatthour ("MWh") sales for the years ended 2002, 2001 and 2000 consisted of:

	Years ended December 31, 2002	2001	2000
(dollars in thousands)			
Operating Revenues			
Retail.	$ 201,052	$ 195,093	$ 185,944
Sales for Resale. . .	70,646	83,804	88,333
Other	2,910	4,567	3,049
Total Operating Revenues.	$ 274,608	$ 283,464	$ 277,326
MWH Sales-Retail.	1,948,190	1,953,154	1,947,857
MWH Sales for Resale. . .	2,107,941	2,368,887	2,575,657
Total MWH Sales	4,056,131	4,322,041	4,523,514

Average Number of Customers

	Years ended December 31, 2002	2001	2000
Residential	73,861	73,249	72,424

Commercial and Industrial	13,194	13,006	12,769
Other	65	65	65
Total Number of Customers. .	87,120	86,320	85,258

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

Change in Operating Revenues	2001 to 2002	2000 to 2001
(In thousands)		
Retail Rates	$ 6,471	$ 8,620
Retail Sales Volume.	(512)	529
Resales and Other Revenues	(14,815)	(3,011)
Increase (Decrease) in Operating Revenues.	$ (8,856)	$ 6,138

In 2002, total electricity sales decreased 6.2 percent compared with 2001, due to reduced sales for resale under the 9701 arrangement with Hydro Quebec and our MS contract, described in more detail below under the headings "Power Supply Expenses" and "Power Contract Commitments". Total operating revenues decreased $8.9 million, or 3.1 percent, in 2002 compared with 2001, due to decreases in sales for resale, partially offset by increased retail operating revenues. Retail operating revenues increased $6.0 million, or 3.1 percent, in 2002 compared with 2001 due to the recognition of $4.4 million of revenue deferred under the Settlement Order. Increased sales to residential and commercial customers also contributed to higher retail revenues, partially offset by a decline in revenues from International Business Machines Corporation ("IBM").

In 2001, total electricity sales decreased 4.5 percent compared with 2000, due principally to reduced sales for resale executed pursuant to the MS contract, described in more detail below under the headings "Power Supply Expenses" and "Power Contract Commitments". Total operating revenues increased $6.1 million, or 2.2 percent, in 2001 compared with 2000 primarily due to increases in retail and other operating revenues, partially offset by a decrease in lower margin wholesale sales. Retail operating revenues increased $9.1 million, or 4.9 percent, in 2001 compared with 2000 due to a 3.42 percent retail rate increase that went into effect January 2001, and an additional increase in revenues from an industrial customer pursuant to revisions in a contract with that customer approved in the Settlement Order.

IBM, the Company's largest customer, operates a manufacturing facility in Essex Junction, Vermont. IBM's electricity requirements for its facility accounted for approximately 25.7, 26.6, and 26.6 percent of the Company's retail MWh sales in 2002, 2001, and 2000, respectively, and 17.3, 19.2, and 16.5 percent of the Company's retail operating revenues in 2002, 2001, and 2000, 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. During 2002, the VPSB approved a modification of this agreement for the last year of the term, 2003. The price of power for the three-year term of the agreement is above our marginal costs of providing incremental service to IBM.

IBM reduced its Vermont workforce by 1,500 during 2002, to a level of approximately 7,000 employees. If future significant losses in electricity sales to IBM were to occur, the Company's earnings could be impacted adversely. If earnings were materially reduced as a result of lower retail sales, the Company would seek a retail rate increase from the VPSB. The Company is not aware of any plans by IBM to further reduce production at its Vermont facility. The Company currently estimates, based on a number of projected variables, the retail rate increase required from all retail customers by a hypothetical shutdown of the IBM facility to be in the range of five to ten percent, inclusive of projected declines in sales to residential and commercial customers.

POWER SUPPLY EXPENSES- Prior to 2001, our inability to recover our power supply costs had been a primary reason for the poor performance of the Company's common stock price during 1999 and 2000. The Settlement Order removed this obstacle by allowing the Company rate recovery of its estimated power supply costs for 2001. Furthermore, the Settlement Order allowed the Company to defer approximately $8.5 million in rate levelization revenues for recognition in 2002 and 2003, if necessary, to achieve its allowed rate of return. The Company recognized approximately $4.4 million of these revenues in 2002 and expects to recognize the remaining balance of $4.1 million during 2003. The deferred recognition of rate levelization revenues allowed the Company to achieve our allowed rate of return in 2002 without further rate relief and is expected to provide the Company with the opportunity to achieve similar operating results in 2003 without further rate relief (See "Power Contract Commitments", and "Rates-Retail Rate Cases" in this section).

Power supply expenses constituted 74.5, 75.3, and 77.7 percent of total operating expenses for the years 2002, 2001, and 2000, respectively. Power supply expenses decreased by $7.6 million or 3.8 percent in 2002 when compared with 2001, and resulted from the following:

a $13.2 million decrease in power purchased for resale, primarily under the 9701 arrangement with Hydro Quebec and our MS contract;

a $3.5 million decrease in the net cost of the 9701 arrangement with Hydro Quebec; and

a $2.1 million increase in the value of additional generation at the Company's hydroelectric plants, that allowed the Company to purchase less power during 2002.

These decreases were partially offset by increased power supply expense in 2002 when compared with 2001 for the following reasons:

a $6.2 million increase in the cost of power purchased from MS;

a $3.7 million net increase in the cost of power purchased from Vermont Yankee, including an offset of $1.4 million for the increase in value of additional generation purchased from the plant; and

a $2.9 million increase in power purchased from independent power producers.

Power supply expenses decreased by $10.5 million or 5.0 percent in 2001 when compared with 2000. The decrease in power supply expenses in 2001 compared with 2000 resulted from the following:

* a $7.7 million decrease in energy costs arising from a power supply arrangement with Hydro Quebec, discussed under the caption "Power Contract Commitments", whereby Hydro Quebec has an option to purchase energy at prices that are below market replacement costs;
* a $5.9 million decrease in Vermont Yankee costs due primarily to the timing of scheduled outages at the plant, where the outage costs, including the costs of replacement power, are deferred and amortized over the subsequent refueling cycle;
* a $4.5 million decrease in power purchased for resale, primarily under a power supply contract discussed under the caption "Power Contract Commitments" below, pursuant to which the Company purchases power from MS that is sufficient to serve pre-established load requirements at a pre-defined price; and

* a $3.0 million decrease in Company-owned generation costs, reflecting a reduction in generation used to maintain system reliability as compared to the prior year when the unavailability of certain transmission equipment required these units to run more frequently.

In 2001, these amounts were partially offset by the disallowance in rates of 2000 Hydro Quebec power contract costs that required $7.5 million of those costs to be charged in 1999 and amortized as a reduction of power supply expenses during 2000, $2.1 million in higher energy prices in 2001 under our MS contract, and higher capacity costs in 2001 of approximately $1.0 million.

The Independent System Operator of New England ("ISO" or "ISO New England") was created to manage the operations of the New England Power Pool ("NEPOOL"), effective May 1, 1999. The ISO works as a clearinghouse for purchasers and sellers of electricity in the deregulated wholesale energy 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 the 9701 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 in 1999, which caused much greater volatility in spot prices for electricity. The cost of securing future power supplies had also risen substantially in tandem with higher summer power supply costs. The Company cannot predict the extent to which future prices will trade above historical levels of cost. If the markets continue to experience the volatility evident since 1999, or the Company's power resources are unavailable during periods of high market prices, 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") between the Company and MS defines the general contract terms under which the parties may transact. 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 have been fulfilled. The PPSA was filed with the Federal Energy Regulatory Commission ("FERC") and the VPSB was notified as well. In August 2002, the PPSA was modified and extended to December 31, 2006.

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 anticipate that arrangements we make to manage power supply risks will be on average more costly than the expected cost of fuel during the periods being hedged because these arrangements typically incorporate a risk premium.

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.

Pursuant to the 1987 Contract, Hydro Quebec has the right to reduce the load factor from 75 percent to 65 percent a total three times over the life of the 1987 Contract. The Company has the contractual right to delay any such reduction by one year under the 1987 Contract. During 2001, Hydro Quebec exercised the first of these options for 2002 and the Company delayed the effective date of this exercise until 2003. The Company estimates that the net cost of Hydro Quebec's exercise of its option will increase power supply expense during 2003 by approximately $0.4 million.

Our contracts with Hydro Quebec contain cross default provisions that allow Hydro Quebec to invoke "step-up" provisions under which the other Vermont utilities that are party to the contract would be required to purchase their proportionate share of the power supply entitlement of the defaulting utility. The Company is not aware of any instance where this provision has been invoked by Hydro Quebec.

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 was extended to 2003), 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 2001 to 2015 period, if documented drought conditions exist in Qu bec.

Under the 9701 arrangement established in December 1997 `, 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, 2002, Hydro Quebec had purchased or called to purchase 458,000 MWh under option B.

In 2002, Hydro Quebec exercised option A and called for deliveries to third parties at a net expense to the Company of approximately $3.0 million including capacity charges.

In 2001, Hydro Quebec exercised option A and option B, and called for deliveries to third parties at a net expense to the Company of approximately $6.5 million, including capacity charges.

In 2000, Hydro Quebec exercised option A and option B, and called for deliveries to third parties at a net expense 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 in 2000.

The Company believes that it is probable that Hydro Quebec will call options A and B for 2003, and has purchased replacement power at a net cost of $4.7 million.

The VPSB, in the Settlement Order stated, "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 the contract year ending October 31, 2002.

On April 17, 2001, an Arbitration Tribunal issued its decision in the arbitration brought by a group of Vermont electric companies and municipal utilities, known as the Vermont Joint Owners ("VJO"), against Hydro Quebec for its failure to deliver electricity pursuant to the VJO contract during the 1998 ice storm. The Company is a member of the VJO.

On July 23, 2001, the Company received approximately $3.2 million representing its share of refunded capacity payments from Hydro Quebec. These proceeds reduced related deferred assets leaving a deferred balance of unrecovered arbitration costs of approximately $1.4 million. We believe it is probable that this balance will ultimately be recovered in rates.

Vermont Yankee Nuclear Power Corporation ("VY")

On July 31, 2002, Vermont Yankee completed the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy"). In addition to the sale of the generating plant, the transaction calls for Entergy through its power contract with VY, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of the Company's energy requirements. The Company continues to own approximately 19 percent of the common stock of VY. Our benefits of the plant sale and the VY power contract with Entergy include:

VY receives cash approximately equal to the book value of the plant assets, removing the potential for stranded costs associated with the plant.

VY and its owners will no longer bear operating risks associated with running the plant.

VY and its owners will no longer bear the risks associated with the eventual decommissioning of the plant.

Prices under the Power Purchase Agreement between VY and Entergy (the "PPA") range from $39 to $45 per megawatt-hour for the period beginning January 2003, substantially lower than the forecasted cost of continued ownership and operation by VY. Contract prices ranged from $49 to $55 for 2002, higher than the forecasted cost of continued ownership for 2002.

The PPA calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, the contract prices are not adjusted upward.

The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the Entergy plant. Payments totaling $0.5 million were made to VY's non-Vermont sponsors in return for guarantees those sponsors made to Entergy to finalize the VY sale. Although the sale closed on July 31, 2002, the Company's distribution of the sale proceeds and final accounting for the sale are pending certain regulatory approvals and the resolution of certain closing items between VY and Entergy. The Company expects its share of the VY power plant sale proceeds, estimated at between $7 million and $8 million, to be distributed in the latter part of 2003. The sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervener parties to the VPSB approval proceeding appealed the VPSB approval to the Vermont Supreme Court. That appeal is pending. If the appellants prevail on their appeal, the VPSB could be required to conduct additional proceedings or to reconsider its order approving the sale.

OTHER OPERATING EXPENSES- Other operating expenses decreased $1.7 million, or 10.9 percent in 2002 compared with 2001. The decrease was primarily due to reduced consulting costs of approximately $1.0 million and reduced distribution expenses of $0.6 million. Other operating expenses are not expected to increase significantly during 2003.

Other operating expenses decreased $1.7 million, or 9.7 percent in 2001 compared with 2000. The decrease was primarily due to a $3.2 million charge during 2000 for disallowed regulatory litigation costs, ordered by the VPSB as part of the Settlement Order, offset in part by increased outside service expense during 2001.

TRANSMISSION EXPENSES-Transmission expenses increased $1.1 million, or 7.7 percent, in 2002 compared with 2001. The Company's relative share of transmission costs varies with the peak demand recorded on Vermont's transmission system. The Company's share of those costs increased due to its increased load growth, relative to other Vermont utilities, and also because of increased transmission investment by VELCO.

Transmission expenses decreased $0.1 million or 0.8 percent in 2001 compared with 2000.

During 2002, the Federal Energy Regulatory Commission ("FERC") accepted ISO New England's request to implement a standard market design ("SMD") governing wholesale energy sales in New England. The ISO implemented its SMD plan on March 1, 2003. SMD includes a system of locational marginal pricing of energy, under which prices are determined by zone, and based in part on transmission congestion experienced in each zone. Currently, the State of Vermont constitutes a single zone under the plan, although pricing may eventually be determined on a more localized ("nodal") basis. The Company does not expect the implementation of this SMD in its current form, which denominates Vermont as a single pricing zone, to have a material impact on the Company's power supply or transmission costs. The FERC has suggested that change to nodal pricing might be appropriate as early as 18 months after the implementation of SMD. The Company believes that this could result in a material adverse impact on its power supply or transmission costs.

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking to amend its regulations and modify its existing pro forma open access transmission tariff to require that all public utilities with open access transmission tariffs modify their tariffs to reflect non-discriminatory, standardized transmission service and standard wholesale electric market design. This rulemaking, known as the "SMD NOPR," proposes to implement standard market design and locational marginal pricing in all regions of the United States, including New England. The SMD NOPR is currently in the rulemaking comment period. It is uncertain whether or how implementation of FERC's SMD NOPR, if and when approved, may differ from the ISO New England SMD plan, or how implementation of the SMD NOPR could impact the Company's power supply or transmission costs, although the impacts could be material.

During 2002, ISO New England and the New York Independent System Operator filed and then withdrew their petition with the FERC proposing to establish a single Northeastern Regional Transmission Organization ("NERTO") encompassing the six New England states and New York. ISO New England has indicated an intention to file a petition with FERC to create a regional transmission organization comprising six New England states now part of the ISO.

VELCO has proposed a project to substantially upgrade Vermont's transmission system (the "Northwest Reliability Project"), principally to support reliability and eliminate transmission constraints in northwestern Vermont, including most of the Company's service territory. The proposed Northwest Reliability Project must be approved by the VPSB. If approved, the project is estimated to cost approximately $150 million over a seven to ten year period. Under current NEPOOL and ISO New England rules, which require qualifying large transmission project costs to be shared among all New England utilities, the Company would expect the costs of this project to be allocated throughout the New England region, with Vermont utilities responsible for approximately five percent of the total project costs. However, in response to FERC's SMD NOPR and as part of ISO New England's SMD plan, ISO New England is considering changes to the transmission cost allocation rules which could modify or eliminate the opportunity to allocate costs associated with the Northwest

Reliability Project to the New England region as a whole. The Company has vigorously advocated for continuation of the current cost allocation rules. If these rules are modified or eliminated, the Company and other Vermont utilities could be required to bear a greater proportion, and potentially all, of the cost of the Northwest Reliability Project.

MAINTENANCE EXPENSES-Maintenance expenses increased $1.7 million or 25.0 percent in 2002 compared with 2001, due to increased expenditures related to storm damage and increased right-of-way maintenance programs.

Maintenance expenses increased $0.5 million or 7.2 percent in 2001 compared with 2000 due to increased expenditures on right-of-way maintenance programs.

DEPRECIATION AND AMORTIZATION-Depreciation and amortization expense decreased $0.1 million or 1.0 percent in 2002 compared with 2001 due to reductions in depreciation of utility plant in service, partially offset by increased amortization of software costs.

Depreciation and amortization expense decreased $1.0 million or 6.6 percent in 2001 compared with 2000 due to reductions in amortization of demand side management costs that were only partially offset by increased depreciation of utility plant in service.

INCOME TAXES-Income tax expense decreased $0.9 million in 2002 compared with 2001 due to a decrease in the Company's taxable income. Income tax expense increased $7.6 million in 2001 when compared with that of 2000 due to an increase in the Company's taxable income.

OTHER INCOME-Other income increased $0.4 million in 2002 compared with 2001 due primarily to the VY recognition of deferred tax assets arising in conjunction with the sale of the VY plant,, offset in part by payments made to out-of-state VY sponsors necessary to close the sale of the VY plant.

Other income decreased $0.3 million in 2001 compared with 2000 due in part to reduced interest income from the reduced investment returns available in 2001.

INTEREST EXPENSE-Interest expense decreased $0.9 million or 12.3 percent in 2002 compared with 2001 primarily due to scheduled and early redemptions of long-term debt and reduced short-term borrowing rates offset in part by higher average balances for short-term borrowings. Interest expense on long-term debt is expected to rise approximately $0.9 million in 2003 due to increased average debt levels from long-term bonds issued in December 2002.

Interest expense decreased $0.2 million or 3.0 percent in 2001 compared with 2000 primarily due to scheduled reductions in long-term debt offset in part by a $12 million term loan made on August 24, 2001.

DIVIDENDS ON PREFERRED STOCK- Dividends on preferred stock decreased $0.8 million, or 90 percent in 2002 compared with 2001 due to the repurchase of all outstanding preferred stock other than the 4.75 percent Class B shares. Dividends on preferred stock are expected to be negligible during 2003. See the discussion under the caption, "Liquidity and Capital Resources-Financing and Capitalization".

Dividends on preferred stock decreased $81,000 or 8.0 percent in 2001 compared with 2000 due to repurchases of preferred stock.

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 EPA, 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, 2002, our total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $27.2 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 waiting 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 reimburse 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 $13.0 million over the next 32 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 some other jurisdictions, "sharing" has been accomplished by allowing utilities to recover costs over time without a rate of return. 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 Barge Canal site 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- The Company reached a final settlement agreement with the Department in its 1998 rate case during November 2000. The final settlement agreement contained the following provisions:

* The Company received 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 were set at levels that recover the Company's Hydro Quebec VJO contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;
* The Company agreed 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 in 2000 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 were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2002 and 2003;
* The Company agreed 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;
* The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in a 1997 rate case; and
* The Company agreed to an earnings limitation for its electric operations in an amount equal to its allowed rate of return of 11.25 percent, with amounts earned over the limit being used to write off regulatory assets.

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

* The Company and customers shall 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, adjusted for inflation; and
* The Company's further investment in non-utility operations is restricted.

The Company earned approximately $4.4 million less than its allowed rate of return during 2002 before including in earnings deferred revenues in the same amount.

The Company earned approximately $30,000 in excess of its allowed rate of return during 2001 before writing off regulatory assets in the same amount.

The VPSB, in its order approving VY's sale of its nuclear power plant to

Entergy, ordered the Company and Central Vermont Public Service each to file on or before April 15, 2003, a cost-of-service study based on actual 2002 data, to enable the VPSB to determine whether an adjustment to rates is justified in 2003 or 2004. The Company believes this filing will support the Company's current rates and does not intend to request a rate increase or decrease when this filing is made. The VPSB could initiate an investigation of the Company's rates based on this filing, requiring the Company to complete a rate case, and the VPSB could order an adjustment to the Company's rates based on its findings and conclusions. If the VPSB ordered the Company to reduce its rates in 2003 or 2004, this could have a material adverse effect on our operating results, cash flows and ability to pay dividends at current levels.

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, net of customer advances for construction, over the past three years and forecasted for 2003 are as follows:

	Generation	Transmission	Distribution	Conservation	Other*	Total
(In thousands)						
Actual:						
2000	$ 1,937	$ 348	$ 7,316	**	$ 5,876	$15,477
2001	2,323	1,219	8,567	**	3,529	15,638
2002	3,258	1,827	9,173	**	7,267	21,525
Forecast:						
2003	$ 2,578	$ 3,200	$ 8,638	**	$ 8,088	$22,504

* Other includes $1.3 million in 2000, $1.5 million in 2001, $1.8 million in 2002, and an estimated $2.3 million in 2003 for the Pine Street Barge Canal site.

**A statewide 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 was $0.60 per share for the year ended December 31, 2002. The Settlement Order had limited the annual dividend rate at its then current level of $0.55 per share until short-term credit facilities were replaced with long-term debt or equity financing. The Company used proceeds of a $42 million long-term debt issue in December 2002 to replace all short-term borrowings, satisfying the conditions in the Settlement Order and permitting the Company to raise its dividend. The annual dividend rate was increased from $0.55 per share to $0.76 per share beginning with the $0.19 quarterly dividend declared in December 2002. The Company intends to increase the dividend in a measured consistent manner until the payout ratio falls between 50 percent and 60 percent of anticipated earnings. The Company believes this payout ratio to be consistent with that of other utilities having similar risk profiles.

FINANCING AND CAPITALIZATION-Internally-generated funds provided approximately 49 percent, 100 percent, and 41 percent, of requirements for 2002, 2001 and 2000, respectively. The 2002 rate of internally generated funding requirements was reduced because of accelerated redemptions of preferred stock and common stock repurchases described in more detail below. Internally generated funds, after payment of dividends, provide capital requirements for construction, sinking funds and other requirements. We anticipate that for 2003, internally generated funds will provide approximately 71 percent of total capital requirements for regulated operations, the remainder to be derived from bank loans.

The Company is not dependent on the use of off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets through special purpose entities. We do have material power supply commitments that are discussed in detail under the captions "Power Contract Commitments" and "Power Supply Expenses". We also own an equity interest in VELCO, which requires the Company to contribute capital when required and to pay a portion of VELCO's operating costs.

At December 31, 2002, our capitalization consisted of 47.6 percent common equity and 52.4 percent long-term debt.

The Company has a $20.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by KeyBank National Association ("KeyBank"), expiring June 2003 (the "Fleet-Key Agreement"). The Fleet-Key Agreement is unsecured and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was $2.5 million outstanding with a weighted average rate of 4.25 percent on the Fleet-Key Agreement at December 31, 2002. There was no non-utility short-term debt outstanding at December 31, 2002 or 2001.

The Company negotiated a $12.0 million, two-year, unsecured loan agreement with Fleet, joined by KeyBank, on August 24, 2001. The $12.0 million loan was repaid on December 16, 2002.

On March 15, 2002, the Company redeemed $5.1 million of the 10.0 percent first mortgage bonds due June 1, 2004.

During March and June 2002, the Company repurchased $11.0 and $1.0 million, respectively, of the 7.32 percent Class E preferred stock outstanding. On May 1, 2002, the Company redeemed $0.3 million of the 7.0 percent Class C preferred stock outstanding. During November 2002, the Company redeemed $0.2 million of the 9.375 percent Class D preferred stock outstanding.

On November 19, 2002, the Company completed a "Dutch Auction" self-tender offer and repurchased 811,783 shares, or approximately 14 percent, of its common stock outstanding for approximately $16.3 million.

See Note D, Preferred Stock, and Note F, Long Term Debt for additional information.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2003.

The credit ratings of the Company's securities at December 31, 2002 are:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BBB+	Baa1	BBB
Preferred stock	BBB	Ba1	BB

On August 29, 2002, Moody's upgraded the Company's senior secured debt rating to Baa1 from Baa2. The outlook for the rating is stable. On September 29, 2002, Fitch Ratings upgraded the rating of the Company's first mortgage bonds to BBB+ from BBB, with a stable outlook. On September 23, 2002, Standard and Poor's Ratings Services affirmed its BBB rating of the Company's senior secured debt, with a stable outlook.

In the event of a change in the Company's first mortgage bond credit rating to below investment grade, scheduled payments under the Company's first mortgage bonds would not be affected. Such a change would require the Company to post what would currently amount to a $4.3 million bond under our remediation agreement with the EPA regarding the Pine Street Barge Canal site. The MS contract requires credit assurances if the Company's first mortgage bond credit ratings are lowered to below investment grade by any two of the three credit rating agencies listed above.

The following table presents a summary of certain material contractual obligations existing as of December 31, 2002.

(In thousands)	Payments Due by Period TOTAL	2003	2004 and 2005	2006 and 2007	After 2007
Long-term debt	$ 101,000	$ 8,000	$ -	$ 14,000	$ 79,000
Interest on long-term debt	72,797	7,047	13,068	12,068	40,614
Preferred stock	85	30	55	-	-
Capital lease obligations	5,287	407	814	814	3,252
Hydro-Quebec power supply contracts	671,268	47,285	101,368	101,872	420,743
MS power supply contract	184,108	55,884	83,941	44,283	-
Vermont Yankee	296,909	36,308	64,421	64,130	132,050
Total	$1,331,454	$154,961	$263,667	$237,167	$675,659

PENSION. Due to sharp declines in the equity markets during 2001 and 2002, the value of assets held in trusts to satisfy the Company's pension plan obligations has decreased. The Company's pension plan assets are primarily made up of public equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension costs in future periods.

The Company's funding policy is to make voluntary contributions to its defined benefit plans before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company made voluntary pension plan contributions totaling $1.0 million between September 1, 2002 and December 31, 2002. The Company plans to make additional voluntary contributions totaling $1.0 million before June 30, 2003. The Company's pension costs and cash funding requirements could increase in future years in the absence of recovery in the equity markets.

OTHER REGULATORY PROCEEDINGS AND LITIGATION-In a series of Vermont regulatory proceedings, the Company has agreed to undertake a process known as "distributed utility planning" as part of its transmission and distribution planning process. Distributed utility planning requires the Company to evaluate conservation-related alternatives and distributed generation alternatives to typical transmission and distribution capital investments. In certain circumstances, the Company may be required to implement conservation or distributed generation alternatives in lieu of, or in addition to, traditional transmission and distribution capital investments, where societal cost savings associated with conservation or distributed generation, including the costs associated with avoided electricity sales, justify the expenditures. The Company is uncertain of the potential magnitude of future spending requirements for this program, but note they could be material. Costs associated with conservation measures or distributed generation facilities not owned by the Company would be deferred as regulatory assets pending future rate proceedings.

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville Dam hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, complaining that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company has petitioned the VPSB to make additional dam improvements at the facility at an estimated cost of $350,000. The VPSB must approve the Company's petition before the proposed improvements can be implemented. This regulatory proceeding is pending and the Company is unable to predict whether the Company's petition will be approved or whether the VPSB will impose regulatory conditions or penalties.

FUTURE OUTLOOK

COMPETITION AND RESTRUCTURING-The electric utility business are 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;
* new regulations and legislation intended to foster competition, also known as restructuring; and
* increasing volatility of wholesale market prices for electricity.

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 costs of service, 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 retail level. Recent difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards deregulation in Vermont. Alternate forms of performance-based regulation currently appear as possible intermediate steps towards deregulation. 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 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.

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase the Bellows Falls hydroelectric facility from a third party, and the associated distribution plant owned by the Company within the town. In March 2002, voters in Rockingham approved an article authorizing Rockingham to create a municipal utility by acting to acquire a municipal plant, which would include the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that neither our remaining customers nor our shareholders effectively subsidize a Rockingham municipal utility.

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 ("FASB") had agreed to review the accounting for closure and removal costs, including decommissioning. The FASB issued a new statement in August 2001 for "Accounting for Asset Retirement Obligations", which provides guidance on accounting for nuclear plant decommissioning costs, as well as other asset retirement costs. The Company has not yet determined what impact, if any, the new accounting standard will have on its investment in VY. We do not believe that changes in such accounting, if required, would have an adverse effect on the results of our 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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

GREEN MOUNTAIN POWER CORPORATION
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All other schedules are omitted as they are either not required, not applicable or the information is otherwise provided.

Consent and Report of Independent Public Accountants

Arthur Andersen LLP 77
Deloitte and Touche LLP

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 Decembe 2002	2001
OPERATING REVENUES	$274,608	$283,464
OPERATING EXPENSES		
Power Supply		
Vermont Yankee Nuclear Power Corporation	35,252	30,114
Company-owned generation	5,067	4,742
Purchases from others	153,129	166,209
Other operating	14,188	15,924
Transmission	15,221	14,130
Maintenance	8,854	7,108
Depreciation and amortization	14,151	14,294
Taxes other than income	7,623	7,536
Income taxes	6,043	6,948
Total operating expenses	259,528	267,005
OPERATING INCOME	15,080	16,459
OTHER INCOME		
Equity in earnings of affiliates and non-utility operations	2,777	2,253
Allowance for equity funds used during construction	233	210
Other (deductions) income, net	(525)	(90)
Total other income	2,485	2,373
INCOME BEFORE INTEREST CHARGES	17,565	18,832
INTEREST CHARGES		
Long-term debt	5,214	6,073
Other	1,059	1,154
Allowance for borrowed funds used during construction	(103)	(188)
Total interest charges	6,170	7,039
INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS	11,395	11,793
Dividends on preferred stock	96	933

INCOME (LOSS) FROM CONTINUING OPERATIONS	11,299	10,860	
Income (Loss) on disposal, including provisions for operating losses during phaseout period, net of applicable income taxes.	99	(182)	
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 11,398	$ 10,678	$
EARNINGS PER SHARE			
Basic earnings (loss) per share from continuing operations	$ 2.02	$ 1.93	$
Basic earnings (loss) per share from discontinued operations	0.02	(0.03)	
Basic earnings (loss) per share	$ 2.04	$ 1.90	$
Diluted earnings (loss) per share from continuing operations	$ 1.96	$ 1.88	$
Diluted earnings (loss) per share from discontinued operations	0.02	(0.03)	
Diluted earnings (loss) per share	$ 1.98	$ 1.85	$
Cash dividends declared per share	$ 0.60	$ 0.55	$
Weighted average shares outstanding-basic	5,592	5,630	
Weighted average equivalent shares outstanding-diluted	5,756	5,789	
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME	2002	2001	
Net income	$ 11,398	$ 10,678	$
Minimum pension liability adjustment, net of $1,612 related income tax	(2,374)	-	
Other comprehensive income, net of tax	$ 9,024	$ 10,678	$

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	FOR THE YEARS ENDED DECEMBER 31, 2002	2001	2000
OPERATING ACTIVITIES:			
Net income (loss) before preferred dividends	$ 11,494	$ 11,611	$ (5,840)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	14,151	14,294	15,304
Dividends from associated companies less equity income.	415	280	(26)
Allowance for funds used during construction	(335)	(398)	(512)
Amortization of deferred purchased power costs	3,236	3,767	5,575
Deferred income taxes	2,430	(2,167)	161
Provision for chargeoff of deferred regulatory asset	-	-	3,229
Deferred purchased power costs	(2,003)	1,126	(6,692)
Accrued purchase power contract option call	-	(8,276)	8,276
Adjustment to provision for loss on segment disposal	(99)	182	6,549
Arbitration costs recovered (deferred)	-	3,229	(3,184)
Rate levelization liability	(4,483)	8,527	-
Environmental and conservation deferrals, net	(2,194)	(3,380)	(2,073)
Changes in:			
Accounts receivable and accrued utility revenues	(896)	6,483	(3,987)
Prepayments, fuel and other current assets	850	300	(931)
Accounts payable and other current liabilities	(55)	128	(4,337)

Accrued income taxes payable and receivable	5,010	1,187	(372)
Other	1,556	(1,603)	(181)
Net cash provided by continuing operations.	29,077	35,290	10,959
Net change in discontinued segment.	-	(1,797)	245
Net cash provided by operating activities	29,077	33,493	11,204
INVESTING ACTIVITIES:			
Construction expenditures	(19,543)	(12,963)	(13,853)
Investment in associated companies.	(392)	-	-
Proceeds from subsidiary sales.	-	-	6,000
Investment in nonutility property	(206)	(212)	(187)
Net cash used in investing activities	(20,141)	(13,175)	(8,041)
FINANCING ACTIVITIES:			
Proceeds from issuance of long term debt.	42,000	-	-
Payments to acquire treasury stock.	(16,319)	-	-
(Reduction in) Proceeds from term loan.	(12,000)	12,000	-
Repurchase of preferred stock	(12,536)	(235)	(1,640)
Issuance of common stock.	1,037	1,655	1,250
Proceeds (purchases) of certificate of deposit.	-	16,173	(15,437)
Power supply option obligation.	-	(16,012)	15,419
Reduction in long-term debt	(13,322)	(9,700)	(6,700)
Short-term debt, net.	2,500	(15,500)	7,600
Cash dividends.	(3,393)	(4,034)	(4,011)
Net cash used in financing activities	(12,033)	(15,653)	(3,520)
Net increase (decrease) in cash and cash equivalents. .	(3,097)	4,665	(356)
Cash and cash equivalents at beginning of period. . . .	5,006	341	696
Cash and cash equivalents at end of period.	$ 1,909	$ 5,006	$ 341
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid year-to-date for:			
Interest (net of amounts capitalized)	$ 6,048	$ 6,936	$ 7,185
Income taxes.	2,349	9,622	1,191
SUPPLEMENTAL DISCLOSURE OF NON-CASH INFORMATION:			
Minimum pension liability adjustment, net	$ 2,374	$ -	$ -

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	DECEMBER 31,	
	2002	2001

(in thousands)

ASSETS		
UTILITY PLANT		
Utility plant, at original cost.	$311,543	$302,489
Less accumulated depreciation.	122,197	119,054
Net utility plant.	189,346	183,435
Property under capital lease	5,287	5,959
Construction work in progress.	8,896	7,464
Total utility plant, net	203,529	196,858
OTHER INVESTMENTS		
Associated companies, at equity.	14,101	14,093
Other investments.	7,451	6,852
Total other investments.	21,552	20,945
CURRENT ASSETS		
Cash and cash equivalents.	1,909	5,006
Accounts receivable, less allowance for doubtful accounts of $547 and $613	17,253	17,111
Accrued utility revenues	6,618	5,864
Fuel, materials and supplies, at average cost.	3,349	4,058
Prepayments.	1,901	1,976
Income tax receivable.	-	1,699
Other.	402	469
Total current assets	31,432	36,183
DEFERRED CHARGES		
Demand side management programs.	6,434	6,961
Purchased power costs.	2,323	3,504
Pine Street Barge Canal.	13,019	12,425
Power supply derivative deferral	18,405	37,313
Other.	11,413	12,265
Total deferred charges	51,594	72,468
NON-UTILITY		
Other current assets	8	8
Property and equipment	249	250
Other assets	738	817
Total non-utility assets	995	1,075
TOTAL ASSETS	$309,102	$327,529

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	DECEMBER 31, 2002	DECEMBER 31, 2001
(in thousands except share data)		
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,782,496 and 5,701,010)	$ 19,276	$ 19,004
Additional paid-in capital.	75,347	74,581
Retained earnings	16,171	8,070
Accumulated other comprehensive income.	(2,374)	-
Treasury stock, at cost (827,639 and 15,856 shares)	(16,698)	(378)
Total common stock equity	91,722	101,277
Redeemable cumulative preferred stock	55	12,325
Long-term debt, less current maturities	93,000	74,400
Total capitalization.	184,777	188,002
CAPITAL LEASE OBLIGATION.	5,287	5,959
CURRENT LIABILITIES		
Current maturities of preferred stock	30	235
Current maturities of long-term debt.	8,000	9,700
Short-term debt	2,500	-
Accounts payable, trade and accrued liabilities . .	7,431	7,237
Accounts payable to associated companies.	8,940	8,361
Rate levelization liability	4,091	8,527
Customer deposits	898	971
Interest accrued.	1,081	1,100
Other	5,520	2,945
Total current liabilities	38,491	39,076
DEFERRED CREDITS		
Power supply derivative liability	18,405	37,313
Accumulated deferred income taxes	26,471	23,759
Unamortized investment tax credits.	3,130	3,413
Pine Street Barge Canal cleanup liability	8,833	10,059
Other	21,767	18,247
Total deferred credits.	78,606	92,791
COMMITMENTS AND CONTINGENCIES		
NON-UTILITY		
Net liabilities of discontinued segment	1,941	1,701
Total non-utility liabilities	1,941	1,701
TOTAL CAPITALIZATION AND LIABILITIES.	$309,102	$327,529

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

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

	COMMON STOCK SHARES	COMMON STOCK AMOUNT	PAID-IN CAPITAL	RETAINED EARNINGS	ACCUM COMPREH OTHER
	(Dollars in thousands)				
BALANCE, DECEMBER 31, 1999 . . .	5,409,715	$18,085	$ 72,594	$ 10,344	$
Common Stock Issuance:					
DRIP and ESIP.	157,790	526	764	-	
Compensation Program:					
Restricted Shares	(809)	(3)	(37)	-	
Net Loss	-	-	-	(5,840)	
Other Comprehensive Income . . .	-				
Common Stock Dividends	-	-	-	(2,997)	
Preferred Stock Dividends: . . .	-	-	-	(1,014)	
BALANCE, DECEMBER 31, 2000 . . .	5,566,696	18,608	73,321	493	
Common Stock Issuance:					
DRIP and ESIP.	105,767	352	1,218	-	
Compensation Programs:					
Restricted Shares and ISOP. .	12,691	44	42	-	
Net Income	-	-	-	11,611	
Other Comprehensive Income					
Common Stock Dividends	-	-	-	(3,101)	
Preferred Stock Dividends: . . .	-	-	-	(933)	
BALANCE, DECEMBER 31, 2001 . . .	5,685,154	19,004	74,581	8,070	
Common Stock Issuance:					
DRIP and ESIP.	28,682	95	424	-	
Common stock repurchase.	(811,783)	-	-	-	
Compensation Programs:					
Restricted Shares and ISOP. .	52,804	177	342	-	
Net Income	-	-	-	11,494	
Other Comprehensive Income(Loss)	-	-	-	-	
Common Stock Dividends	-	-	-	(3,297)	
Preferred Stock Dividends: . . .	-	-	-	(96)	
BALANCE, DECEMBER 31, 2002 . . .	4,954,857	$19,276	$ 75,347	$ 16,171	$

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

CONSOLIDATED CAPITALIZATION DATA
GREEN MOUNTAIN POWER CORPORATION At December 31,

	AUTHORIZED	SHARES ISSUED AND OUTSTANDING 2002	2001	2002	2001
				(In thousands)	
COMMON STOCK					
Common Stock, $3.33 1/3 par value.	10,000,000	4,954,857	5,685,154	$19,276	$19,004

	AUTHORIZED	ISSUED	OUTSTANDING 2002	2001	2002	2001
	Shares				(In thousands)	
REDEEMABLE CUMULATIVE PREFERRED STOCK, 100 PAR VALUE						
4.75%, Class B, redeemable at 101 per share.	15,000	15,000	850	1,150	$ 85	$ 115
7%, Class C	15,000	15,000	-	2,850	-	285
9.375%, Class D, Series 1,.	40,000	40,000	-	1,600	-	160
7.32%, Class E, Series 1.	200,000	120,000	-	120,000	-	12,000
TOTAL PREFERRED STOCK		. . . .	$		85	$ 12,560

(In thousands)	2002	2001
LONG-TERM DEBT		
Fleet/Key Term Loan due August 2003.	$ -	$12,000
FIRST MORTGAGE BONDS		
6.29% Series due 2002.	-	8,000
6.41% Series due 2003.	8,000	8,000
10.0% Series due 2004.	-	5,100
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
6.04 % Series due 2017-Cash sinking fund commences 2011. .	42,000	-
Total Long-term Debt Outstanding	101,000	84,100
Less Current Maturities (due within one year).	8,000	9,700
TOTAL LONG-TERM DEBT, LESS CURRENT MATURITIES.	$ 93,000	$74,400

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 with a principal service territory that includes approximately one-quarter of Vermont's population. Nearly all of the Company's net income is generated from retail sales in its regulated electric utility operation, which purchases and generates electric power and distributes it to approximately 88,000 customers. At December 31, 2002, the Company's primary unregulated subsidiary investment was Northern Water Resources, Inc. ("NWR"), which had invested in energy generation, energy efficiency and wastewater treatment projects across the United States. In 2000, the Company disposed of most of the assets of NWR. Green Mountain Power Investment Company ("GMPIC") was created in December 2002 to hold the Company's investments in Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VY") and Vermont Electric Power Company, Inc. ("VELCO"). 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, Green Mountain Propane Gas Company ("GMPG") and GMP Real Estate Corporation. The results of these subsidiaries and the Company's unregulated rental water heater program, excluding NWR, are included in earnings of affiliates and non-utility operations in the Other (Deductions) Income section of the Consolidated Statements of Income. Summarized financial information for these subsidiaries, and the Company's unregulated water heater program, which earned approximately $0.3 million in 2002 is as follows:

	Years ended December 31,		
	2002	2001	2000
In thousands			
Revenue. . .	$ 997	$1,012	$1,034
Expense. . .	744	749	$ 696
Net Income .	$ 253	$ 263	$ 338

The Company accounts for its investments in VY, 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 accounting principles generally accepted in the United States applicable to rate-regulated enterprises in accordance with Statement of Financial Accounting Standards No. ("SFAS") 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 increasing competition that restricts the Company's ability to recover specific costs, and 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 as summarized in the following table:

SFAS 71 Deferred charges

	At December 31,	
	2002	2001
(in thousands)		
Power Supply Derivative. . .	$18,405	$37,313
Pine Street Barge Canal. . .	13,019	12,425
Power Supply	4,492	6,112
Demand Side Management . . .	6,434	6,961
Preliminary Survey	1,202	1,094
Storm Damages.	1,905	2,169
Regulatory Commission costs.	1,774	873
Tree Trimming.	905	905
Restructuring Costs.	2,216	3,502
Other.	1,242	1,114
Total Deferred Charges . . .	$51,594	$72,468

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 the Federal Energy Regulatory Commission ("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, 2002, based upon the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss should 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 a 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.

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 3.2 percent at the beginning of 2002, 3.5 percent of total depreciable property at the beginning of 2001, and 3.5 percent at the beginning of 2000.

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

7. Operating Revenues. Operating revenues consist principally of sales of electric energy at regulated rates. Revenue is recognized when electricity is delivered. 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. Prior to the sale of the Vermont Yankee ("VY") nuclear generating plant (See Note B) the Company deferred and amortized certain replacement power, maintenance and other costs associated with outages at the VY generating plant. In addition, the Company accrued and amortized 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 its demand side management program and other regulatory assets, in a manner consistent with authorized or expected ratemaking treatment.

Other deferred charges totaled $11.4 million and $12.3 million at December 31, 2002 and 2001, respectively, consisting of regulatory deferrals of storm damages, rights-of-way maintenance, other employee benefits, preliminary survey and investigation charges, transmission interconnection charges, regulatory tax assets 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. During the year ended December 31, 2000, the Company established a stock incentive plan for all employees, and granted 335,300 options exercisable over vesting schedules of between one and four years. During 2002 and 2001, the Company granted additional options of 80,300 and 56,450, respectively. See Note C for additional information. SFAS 123 requires disclosure of pro-forma information regarding net income and earnings per share. The information presented below has been determined as if the Company accounted for its employee and director stock options under the fair value method of that statement.

Pro-forma net income (loss)	For the years ended December 31, 2002	2001	2000
In thousands, except per share amounts			
Net income (loss) reported.	$11,398	$10,678	$(6,854)
Pro-forma net income (loss)	$11,246	$10,527	$(6,911)
Net income (loss) per share			
As reported-basic	$ 2.04	$ 1.90	$ (1.25)
Pro-forma basic	$ 2.01	$ 1.87	$ (1.26)
As reported-diluted	$ 1.98	$ 1.85	$ (1.25)
Pro-forma diluted	$ 1.95	$ 1.82	$ (1.26)

10. Major Customers. The Company had one major retail customer, International Business Machines Corporation ("IBM"), that accounted for 25.7 percent, 26.6 percent, and 26.6 percent of retail MWh sales, and 17.3 percent, 19.2 percent and 16.5 percent of the Company's retail operating revenues in 2002, 2001 and 2000, respectively.

11. Fair Value of Financial Instruments. The present value of the Company's first mortgage bonds and preferred stock outstanding, if refinanced using prevailing market rates of interest, would decrease from the balances outstanding at December 31, 2002 by approximately 4.7 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 net income.

12. Deferred Credits. At December 31, 2002, the Company had other deferred credits and long-term liabilities of $21.8 million, consisting of reserves for damage claims and accruals for employee benefits, compared with a balance of $18.2 million at December 31, 2001.

13. Environmental Liabilities. The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. Only those site investigation, characterization and remediation costs currently known and determinable can be considered "probable and reasonably estimable" under SFAS 5, "Accounting for Contingencies". As costs become probable and reasonably estimable, reserves are adjusted as appropriate. As reserves are recorded, regulatory assets are recorded to the extent environmental expenditures are expected to be recovered in rates. Estimates are based on studies provided by third parties.

14. Income Taxes. The Company recognizes tax assets and liabilities according to SFAS 109, "Accounting for Income Taxes", for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of assets and liabilities. Investment tax credits associated with utility plant are deferred and amortized over the lives of the related assets. Valuation allowances are provided when necessary against certain deferred tax assets.

15. Purchased Power. The Company records the annual cost of power obtained under long-term contracts as operating expenses.

SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its 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. SFAS 133, as amended by SFAS 137, was effective for the Company beginning 2001.

One objective of the Company's risk management program is to stabilize cash flow and earnings by minimizing power supply risks. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and transmission congestion rights with counter-parties that have at least investment grade ratings. These transactions are used to mitigate the risk of fossil fuel and spot market electricity price increases. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions.

On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings or other comprehensive income effects relating to future periods caused by application of SFAS 133. At December 31, 2002, the Company had a liability reflecting the net negative fair value of the two derivatives described below, as well as a corresponding regulatory asset of approximately $18.4 million. The Company believes that the regulatory asset, determined using the Black's or Black-Scholes option valuation method, is probable of recovery in future rates. The regulatory liability is based on current estimates of future market prices that are likely to change by material amounts.

If a derivative instrument is terminated early because it is probable that a transaction or forecasted transaction will not occur, any gain or loss would be recognized in earnings immediately. For derivatives held to maturity, the earnings impact would be recorded in the period that the derivative is sold or matures.

The Company has a contract with Morgan Stanley Capital Group, Inc. ("MS") used to hedge against increases in fossil fuel prices. MS purchases the majority of the Company's 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, 2006. Management's estimate of the fair value of the future net benefit of this contract at December 31, 2002 is approximately $8.8 million.

We currently have an arrangement that grants Hydro-Quebec an option ("9701") to call power at prices below current and estimated future market rates. This arrangement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for this arrangement at December 31, 2002 is approximately $27.2 million. We use futures contracts to hedge the 9701 call option.

16. Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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.

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

18. New Accounting Standards. In June 2001, the FASB issued Statement of Financial Accounting Standards No. 141, Business Combinations ("SFAS 141"), and Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS 142"). SFAS 141 requires the use of the purchase method to account for business combinations initiated after June 30, 2001 and uses a non-amortization approach to purchased goodwill and other indefinite-lived intangible assets. Under SFAS 142, effective for 2002, goodwill and intangible assets deemed to have indefinite lives will no longer be amortized and will be subject to annual impairment tests. The application of these accounting standards does not materially impact the Company's financial position or results of operations.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), effective for fiscal years beginning after June 15, 2002, which provides guidance on accounting for nuclear plant decommissioning and other asset retirement costs. SFAS 143 prescribes fair value accounting for asset retirement liabilities, including nuclear decommissioning obligations, and requires recognition of such liabilities at the time incurred. The application of this accounting standard is not expected to materially impact the Company's financial position or results of operations.

In October 2001, the FASB issued Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"). SFAS 144 specifies accounting and reporting for the impairment or disposal of long-lived assets. The application of this accounting standard does not materially impact the Company's financial position or results of operations.

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" ("SFAS 146"). SFAS 146 specifies accounting and reporting for costs associated with exit or disposal activities. The application of this accounting standard, which is effective for us during 2003, is not expected to materially impact the Company's financial position or results of operations.

In December 2002, the FASB issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-based Compensation-Transition and Disclosure" ("SFAS 148"). SFAS 148 amends Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting and reporting for stock-based employee compensation. The application of this accounting standard is not expected to materially impact the Company's financial position or results of operations.

B. INVESTMENTS IN ASSOCIATED COMPANIES

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

	PERCENT OWNERSHIP AT DECEMBER 31,		INVESTMENT IN EQUITY AT DECEMBER 31,	
(IN THOUSANDS)	2002	2001	2002	2001
VELCO-common.	28.41%	29.50%	$2,309	$1,932
VELCO-preferred	30.00%	30.00%	305	420
Total VELCO			2,614	2,352
Vermont Yankee- Common.	18.99%	17.88%	9,721	9,725
New England Hydro Transmission-Common . .	3.18%	3.18%	660	761
New England Hydro Transmission Electric-Common.	3.18%	3.18%	1,106	1,255
Total investment in associated companies.			$14,101	$14,093

Undistributed earnings in associated companies totaled approximately $484,000 at December 31, 2002.

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 $12.7 million, $11.5 million, and $9.8 million for the years 2002, 2001 and 2000, respectively. Pursuant to VELCO's Amended Articles of Association, the Company is entitled to approximately 29 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 unaudited financial information for VELCO is as follows:

At and for the years ended December 31,	2002	2001	2000

(In thousands)			
Net income applicable to common stock.	$ 1,094	$ 1,118	$ 1,257
Company's equity in net income	$ 319	$ 308	$ 395
Total assets	$106,613	$89,322	$82,123
Less:			
Liabilities and long-term debt	97,417	81,335	73,874
Net assets	$ 9,196	$ 7,987	$ 8,249
Company's equity in net assets	$ 2,614	$ 2,352	$ 2,456

VERMONT YANKEE. On July 31, 2002, Vermont Yankee ("VY") announced that the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy") had been completed. See Note K for further information concerning our long-term power contract with VY.

During May 2002, prior to the sale of the plant to Entergy, the VY plant had fuel rods that required repair, a maintenance requirement that is not unique to VY. VY closed the plant for a twelve-day period, beginning on May 11, 2002, to repair the rods. The Company's share of the cost for the repair, including incremental replacement energy costs, was approximately $2.0 million. The Company received an accounting order from the VPSB on August 2, 2002, allowing it to defer the additional costs related to the outage, and believes that such amounts are probable of future recovery.

The Company's ownership share of VY has increased from approximately 17.9 percent in 2001 to approximately 19.0 percent currently, due to VY's purchase of certain minority shareholders' interests. The Company's entitlement to energy produced by the Entergy Vermont Yankee nuclear plant has increased from approximately 18 percent to 20 percent of plant production through a series of transactions in connection with the sale of the plant to Entergy.

The increase in equity in earnings of VY resulted from VY's recognition of certain deferred tax assets as a result of the sale of the nuclear plant.

Summarized unaudited financial information for Vermont Yankee is as follows:

At and for the years ended December 31,	2002	2001	2000
(In thousands)			
Earnings:			
Operating revenues	$175,722	$178,840	$178,294
Net income applicable to common stock.	9,454	6,119	6,583
Company's equity in net income	$ 1,745	$ 1,131	$ 1,177
Total assets	$201,616	$723,815	$706,984
Less:			
Liabilities and long-term debt	150,413	669,640	652,663
Net Assets	$ 51,203	$ 54,175	$ 54,321
Company's equity in net assets	$ 9,721	$ 9,725	$ 9,641

C. COMMON STOCK EQUITY

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 416,328 shares were reserved and unissued at December 31, 2002. The Company also funds an Employee Savings and Investment Plan ("ESIP").

At December 31, 2002, there were 82,754 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 a total of 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. Options have only been issued to employees and directors.

The fair values of the options granted in 2002, 2001 and 2000 are $2.27 $4.16 and $2.03 per share, respectively. They were estimated at the grant date using the Black-Scholes option-pricing model. The following table presents information about the assumptions that were used for each plan year, and a summary of the options outstanding at December 31, 2002:

Plan year	Weighted average exercise price	Outstanding options	Remaining Contractual Life	Assumptions used in option pricing model: Risk Free Interest rate	Expected Life in Years	Expected Stock Volatility	Dividend Yield
2000	$ 7.90	236,900	7.6 years	6.05%	5	30.58	4.5%
2001	$16.63	50,400	8.6 years	5.25%	6	32.69	4.0%
2002	$17.37	78,500	9.6 years	4.50%	6.5	16.89	4.5%
Total . . .	$11.14	365,800					

	Total Options	Weighted Average Price	Range of Exercise Prices	Options Exercisable
Outstanding at January 1, 2000 .	-	$ -		
Granted.	335,300	7.90	$ 7.90	
Exercised.	-	-		
Forfeited.	3,400	7.90		
Outstanding at December 31, 2000	331,900	$ 7.90	$ 7.90	-
Granted.	55,450	$16.67	$14.50-$16.78	
Granted.	1,000	12.28	$ 12.28	
Exercised.	17,400	7.90	$ 7.90	
Forfeited.	6,800	10.61	$ 7.90-$16.78	
Outstanding at December 31, 2001	364,150	$ 9.20	$ 7.90-$16.78	95,350
Granted.	80,300	17.82	$16.78-$17.83	
Exercised.	53,250	8.12	$ 7.90-$16.78	
Forfeited.	25,400	9.35	$ 7.90-$18.67	
Outstanding at December 31, 2002	365,800	$11.23	$ 7.90-$17.82	151,775

Options granted are not exercisable until one year after the date of grant. The pro-forma amounts may not be representative of future results 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 table presents a reconciliation of net income to net income available to common shareholders, and the average common shares to average common equivalent shares outstanding:

Reconciliation of net income available for common shareholders and average shares	For the years ended December 31, 2002	2001	2000
(in thousands)			
Net income (loss) before preferred dividends.	$11,397	$11,611	$(5,840)
Preferred stock dividend requirement.	96	933	1,014
Net income (loss) applicable to common stock.	$11,493	$10,678	$(6,854)
Average number of common shares-basic	5,592	5,630	5,491
Dilutive effect of stock options.	164	159	-
Average number of common shares-diluted . . .	5,756	5,789	5,491

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 1,262 restricted shares, issued during 1996 and 1997, became vested under this program during 2002, and no shares remain unvested or unissued at December 31, 2002.

On November 19, 2002, the Company completed a "Dutch Auction" self-tender offer and repurchased 811,783 common shares, or approximately 14 percent, of its common stock outstanding for approximately $16.3 million.

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 $12.1 million of retained earnings were free of restrictions at December 31, 2002.

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, 2002, $220,000 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 and sinking fund requirements provided for any class of preferred stock.

The outstanding Class B preferred stock is subject to annual purchase and sinking fund requirements. The sinking fund requirement is mandatory. The purchase fund requirement is 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 outstanding Class B preferred stock is 300 shares in 2003 and 2004, and 250 shares in 2005.

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 three years are $30,000 each for 2003 and 2004, and $25,000 for 2005.

Class B preferred stock is 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 an early redemption premium. The redemption premium for Class B is $1.00 per share. During 2002, the Company repurchased all $12.0 million of the 7.32 percent Class E preferred stock outstanding. On May 1, 2002, the Company redeemed $0.3 million of the 7.0 percent Class C preferred stock outstanding. During November 2002, the Company redeemed the remaining $0.2 million of the 9.375 percent Class D preferred stock outstanding.

E. SHORT-TERM DEBT

The Company has a $20.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by KeyBank National Association ("KeyBank"), expiring June 2003 (the "Fleet-Key Agreement"). The Fleet-Key Agreement is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was $2.5 million outstanding at a weighted average rate of 4.25 percent under the Fleet-Key Agreement at December 31, 2002. There was no non-utility short-term debt outstanding at December 31, 2002 or 2001.

The Fleet-Key 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-Key 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.

F. LONG-TERM DEBT

On December 16, 2002, the Company issued through private placement $42 million principal amount of first mortgage bonds bearing interest at 6.04 percent per year and maturing on December 1, 2017. The average duration of the bond issuance is twelve years and the bonds are subject to seven equal annual principal payments beginning on December 1, 2011. Proceeds were used to retire all of the Company's short and intermediate term debt, and to repurchase 811,783 shares of the Company's common stock.

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 7.0 percent and 7.1 percent at December 31, 2002 and 2001, 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, as of December 31, 2002, are:

Sinking
Fund and

Maturities

2003	$ 8,000
2004	-
2005	-
2006	14,000
2007	-
Thereafter	79,000
Total Long-term debt	$ 101,000

On March 15, 2002, the Company redeemed the outstanding $5.1 million, 10.0% first mortgage bonds due June 1, 2004.

The Company executed and delivered a $12.0 million, two-year, unsecured loan agreement with Fleet, joined by KeyBank, on August 24, 2001. This $12.0 million loan was repaid on December 16, 2002.

On August 29, 2002, Moody's upgraded the Company's senior secured debt rating to Baa1 from Baa2. The outlook for the rating is stable. On September 29, 2002, Fitch Ratings upgraded the rating of the Company's first mortgage bonds to BBB+ from BBB, with a stable outlook. On September 23, 2002, Standard and Poor's Ratings Services affirmed its BBB rating of the Company's senior secured debt, with a stable outlook.

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, 2002 and 2001, the net regulatory assets were $1,042,000 and $1,096,000, 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, 2002 and December 31, 2001, were as follows:

AT DECEMBER 31,

(In thousands)	2002	2001
DEFERRED TAX ASSETS		
Contributions in aid of construction.	$11,130	$10,435
Deferred compensation and postretirement benefits.	4,570	4,382
Self insurance and other reserves . .	1,369	-
Other	3,032	5,525
	$20,101	$20,342

DEFERRED TAX LIABILITIES		
Property related.	$41,967	$39,518
Demand side management.	1,870	2,059
Deferred purchased power costs. . . .	943	1,450
Pine Street reserve	1,792	855
Other	-	219
	$46,572	$44,101
Net accumulated deferred income tax liability	$26,471	$23,759

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 periods presented:

	YEARS ENDED DECEMBER 31, 2002	2001	2000
(In thousands)			
Net change in deferred income tax . . liability	$ 2,712	$(1,885)	$ 443
Change in income tax related regulatory assets and liabilities .	2,759	(1,149)	184
Change in alternative minimum tax credit.	-	-	-
Change in tax effect of accumulated other comprehensive income.	(1,612)	-	-
Deferred income tax expense (benefit)	$ 3,859	$(3,034)	$ 627

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

YEARS ENDED DECEMBER 31,	2002	2001	2000
(In thousands)			
Current federal income taxes .	$1,873	$ 7,846	$ (786)
Current state income taxes . .	593	2,418	(249)
Total current income taxes . .	2,466	10,264	(1,035)
Deferred federal income taxes.	2,920	(2,296)	461
Deferred state income taxes. .	939	(738)	166
Total deferred income taxes. .	3,859	(3,034)	627
Investment tax credits-net . .	(282)	(282)	(283)
Income tax provision (benefit)	$6,043	$ 6,948	$ (691)

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:

(In thousands)	YEARS ENDED DECEMBER 31, 2002	2001	2000
Income (loss) before income taxes and preferred dividends	$17,537	$18,559	$(6,531)
Federal statutory rate.	34.0%	35.0%	34.0%
Computed "expected" federal income taxes	5,963	6,496	(2,221)
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation.	41	45	83
Dividends received and paid credit.	(575)	(440)	(435)
AFUDC-equity funds.	(80)	(72)	(33)
Amortization of ITC	(282)	(282)	(282)
State tax (benefit)	1,011	1,705	(83)
Excess deferred taxes	(60)	(60)	(60)
Tax attributable to subsidiaries.	(31)	63	2,213
Other	56	(507)	127
Total federal and state income tax (benefit).	$ 6,043	$ 6,948	$ (691)
Effective combined federal and state income tax rate	34.5%	37.4%	10.6%

Non-Utility. The Company's non-utility subsidiaries, excluding NWR, had accumulated deferred income taxes of approximately $2,000 on their balance sheets at December 31, 2002, attributable to depreciation timing differences.

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

(In thousands)	YEARS ENDED DECEMBER 31, 2002	2001	2000
State income taxes	$ (1)	$ -	$ 7
Federal income taxes	(3)	(1)	21
Income tax expense (benefit)	$ (4)	$ (1)	$ 28

The effective combined federal and state income tax rate for the continuing non-utility operations was approximately 40 percent for each of the years ended December 31, 2002, 2001 and 2000. See Note L for income tax information on the discontinued operations of NWR.

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 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.

Due to sharp declines in the equity markets during 2001 and 2002, the value of assets held in trusts to satisfy the Company's pension plan obligations has decreased. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension costs in future periods.

The Company's funding policy is to make voluntary contributions to its defined benefit plans before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company made voluntary pension plan contributions totaling $1.0 million between September 1, 2002 and December 31, 2002 and plans to make voluntary contributions totaling an additional $1.0 million by June 30, 2003. The Company's pension costs and cash funding requirements could increase in future years in the absence of recovery in the equity markets.

As a result of GMP's retirement plan asset return experience, at December 31, 2002, the Company has recognized an additional minimum liability of $2.4 million, net of applicable income taxes, as prescribed by generally accepted accounting principles. The liability is recorded as a reduction to common equity through a charge to other comprehensive income and did not affect net income for 2002.

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 postretirement health care 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, 2002 and 2001.

	At and for the years ended December 31,			
	Pension Benefits		Other Postretirement Benefi	
	2002	2001	2002	2001
(In thousands)				
Change in projected benefit obligation:				
Projected benefit obligation as of prior year end.	$25,895	$23,332	$ 16,491	$14,947
Service cost	668	537	296	241
Interest cost.	1,849	1,737	1,119	1,043
Participant contributions.	-	-	147	151
Change in actuarial assumptions.	-	367	-	-
Actuarial (gain) loss.	3,230	1,650	3,619	1,021
Benefits paid.	(1,650)	(1,670)	(965)	(912)
Administrative expense	(55)	(58)	-	-
Projected benefit obligation as of year end. . . .	$29,937	$25,895	$ 20,707	$16,491

Change in plan assets:				
Fair value of plan assets as of prior year end . .	$24,341	$27,760	$ 10,016	$10,944
Administrative expenses paid	(55)	(58)	-	-
Participant contributions.	-	-	147	151
Employer contributions	1,000	-	819	761
Actual return on plan assets	(2,532)	(1,691)	(1,257)	(928)
Benefits paid.	(1,650)	(1,670)	(965)	(912)
Fair value of plan assets as of year end	$21,104	$24,341	$ 8,760	$10,016
Funded status as of year end	$(8,833)	$(1,554)	$(11,948)	$(6,475)
Unrecognized transition obligation (asset)	(77)	(241)	3,280	3,608
Unrecognized prior service cost.	839	986	(462)	(519)
Unrecognized net actuarial (gain) loss	6,982	(892)	8,379	2,711
Accrued benefits at year end	$(1,089)	$(1,701)	$ (751)	$ (675)

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31,2002, 2001, and 2000 were $408,000, $340,000, and $346,000, 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 Postretirement Benef		
	2002	2001	2000	2002	2001	2000
(In thousands)						
Service cost	$ 668	$ 537	$ 655	$ 296	$ 241	$ 21
Interest cost.	1,849	1,737	1,658	1,119	1,043	1,04
Expected return on plan assets	(2,112)	(2,379)	(2,580)	(851)	(892)	(94
Amortization of transition asset	(164)	(164)	(164)	-	-	
Amortization of prior service cost	147	147	121	(58)	(58)	(5
Amortization of the transition obligation.	-	-	-	328	328	32
Recognized net actuarial gain.	-	(237)	(474)	60	-	
Net periodic benefit cost (income) . .	$ 388	$ (359)	$ (784)	$ 894	$ 662	$ 59

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

For measurement purposes, a 10.0 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2003. This rate of increase gradually declines to 5.5 percent in 2009. The medical 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, 2002 by $3.4 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2002 by $257,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2002 by $2.7 million, and the total of the service and interest cost components of net periodic postretirement cost for 2002 by $202,000.

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. Alternative forms of performance-based regulation currently appear as possible intermediate steps towards deregulation. 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 EPA, 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, 2002, the Company's total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $27.1 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 waiting 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 reimburse 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 $13.0 million over the next 32 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 Settlement Order 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. JOINTLY-OWNED FACILITIES. The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2002, as follows:

	Ownership Interest	Share of Capacity	Utility Plant	Accumulated Depreciation
	(In %)	(In MWh)	(In thousands)	
Highgate	33.8	67.6	$ 10,296	$ 4,657
McNeil	11.0	5.9	8,989	5,078
Stony Brook (No. 1). . .	8.8	31	10,377	8,521
Wyman (No. 4).	1.1	6.8	1,980	1,318
Metallic Neutral Return.	59.4	-	1,563	744

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.

4. RATE MATTERS.

RETAIL RATE CASES- The Company reached a final settlement agreement with the Department in its 1998 rate case during November 2000. The final settlement agreement contained the following provisions:

* The Company received 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 were set at levels that recover the Company's Hydro-Quebec Vermont Joint Owners ("VJO") contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;
* The Company agreed 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 in 2000 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 were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2002 and 2003;
* The Company agreed 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;
* The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the 1997 rate case; and
* The Company agreed to an earnings limitation for its electric operations in an amount equal to its allowed rate of return of 11.25 percent, with amounts earned over the limit being used to write off regulatory assets.

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

* The Company and customers shall 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, adjusted for inflation; and
* The Company's further investment in non-utility operations is restricted.

The Company earned approximately $4.4 million less than its allowed rate of return during 2002 before recognition of deferred revenues in the same amount.

The VPSB, in its order approving VY's sale of its nuclear power plant to Entergy, ordered the Company and Central Vermont Public Service each to file on or before April 15, 2003, a cost-of-service study based on actual 2002 data, to enable the VPSB to determine whether an adjustment to rates is justified in 2003 or 2004. The Company believes this filing will support the Company's current rates and does not intend to request a rate increase or decrease when this filing is made. The VPSB could initiate an investigation of the Company's rates based on this filing, requiring the Company to complete a rate case, and the VPSB could order an adjustment to the Company's rates based on its findings and conclusions. If the VPSB ordered the Company to reduce its rates in 2003 or 2004, this could have a material adverse effect on our operating results, cash flows and ability to pay dividends at current levels.

5. OTHER DEFERRED CHARGES NOT INCLUDED IN RATE BASE. The Company has incurred and deferred approximately $11.1 million in costs for demand side conservation programs, tree trimming, storm damage, unscheduled VY outage costs and federal regulatory commission work of which $1.2 million is being amortized on an annual basis. Currently, the Company amortizes such costs based on amounts being recovered and does not receive a return on certain 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 Department. 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.

6. COMPETITION. During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures, and on March 5, 2002, voters in Rockingham authorized the town to establish its own electric utility, by acting to acquire an existing hydro-generation facility from a third party, and the associated distribution plant owned by the Company within Rockingham. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue reimbursement such that neither our remaining customers nor our shareholders subsidize Rockingham.

7. OTHER LEGAL MATTERS. In a series of Vermont regulatory proceedings, the Company has agreed to undertake a process known as "distributed utility planning" as part of its transmission and distribution planning process. Distributed utility planning requires the Company to evaluate conservation-related alternatives and distributed generation alternatives to typical transmission and distribution capital investments. In certain circumstances, the Company may be required to implement conservation or distributed generation alternatives in lieu of, or in addition to, traditional transmission and distribution capital investments, where societal cost savings associated with conservation or distributed generation, including the costs associated with avoided electricity sales, justify the expenditures. The Company is uncertain of the potential magnitude of future spending requirements for this program, but note they could be material. Costs associated with conservation measures or distributed generation facilities not owned by the Company would be deferred as regulatory assets pending future rate proceedings.

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville Dam hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, complaining that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company has petitioned the VPSB to make additional dam improvements at the facility at an estimated cost of $350,000. The VPSB must approve the Company's petition before the proposed improvements can be implemented. This regulatory proceeding is pending and the Company is unable to predict whether the Company's petition will be approved or whether the VPSB will impose regulatory conditions or penalties.

The Company is involved in other 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. At December 31, 2002, the present value of the Company's obligation is approximately $5.3 million.

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

	Year ending December 31 (In thousands)
2003.	$ 407
2004.	407
2005.	406
2006.	407
2007.	407
Total for 2008-2015	3,253
Total	$ 5,287

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 2002 follows:

	STONY BROOK (Dollars in thousands)
Plant capacity.	352.0 MW
Company's share of output	4.40%
Contract period expires:.	2006
Company's annual share of:	
Interest.	$ 140
Other debt service.	435
Other capacity.	306
Total annual capacity	$ 881

Company's share of long-term debt	$ 2,314

2. Vermont Yankee

The Company has a long-term power purchase contract with Vermont Yankee Nuclear Power Corporation, which sold its nuclear power plant to Entergy Nuclear Vermont Yankee on July 31, 2002. The Company is no longer required to pay its proportionate share of fixed costs associated with the Entergy plant, including when the plant is not operating, though the Company is responsible for finding replacement power at such times.

The VY sale of its nuclear power plant to Entergy also calls for Entergy, through its power contract with VY, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of the Company's energy requirements. The Company continues to own approximately 19 percent of the common stock of VY. Our benefits of the plant sale and the VY power contract with Entergy include:

VY receives cash approximately equal to the book value of the plant assets, removing the potential for stranded costs associated with the plant.

VY and its owners will no longer bear operating risks associated with running the plant.

VY and its owners will no longer bear the risks associated with the eventual decommissioning of the plant.

Prices under the Power Purchase Agreement between VY and Entergy (the "PPA") range from $39 to $45 per megawatt-hour for the period beginning January 2003, substantially lower than the forecasted cost of continued ownership and operation by VY. Contract prices ranged from $49 to $55 for 2002, higher than the forecasted cost of continued ownership for 2002.

The PPA calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, the contract prices are not adjusted upward.

A summary of the PPA, including projected charges for the years indicated, follows:

		Vermont Yankee Contract
(Dollars in thousands except per KWh)		
Capacity acquired		106 MW
Contract period expires		2012
Company's share of output		20%
Annual energy charge.	2002(5 months)	$15,965
estimated	2003-2015	33,352
Average cost per KWh.	2002	0.052
estimated	2003-2015	0.042

Payments totaling $0.5 million were made in 2002 to VY's non-Vermont sponsors in return for guarantees those sponsors made to Entergy to finalize the VY sale.

Although the sale closed on July 31, 2002, the Company's distribution of the sale proceeds and final accounting for the sale are pending certain regulatory approvals and the resolution of certain closing items between VY and Entergy. The Company expects its share of the VY power plant sale proceeds, currently estimated at between $7 million and $8 million, to be distributed in the latter part of 2003.

The sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervener parties to the VPSB approval proceeding appealed the VPSB approval to the Vermont Supreme Court. That appeal is pending. If the appellants prevail on their appeal, the VPSB could be required to conduct additional proceedings or to reconsider its order approving the sale.

3. 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 in December 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. There are specific step-up provisions that provide that in the event any 1987 Contract participant fails to meet its obligation under the 1987 Contract with Hydro-Quebec, the remaining contract participants, including the Company, will "step-up" to the defaulting participant's share on a prorated basis.

Hydro-Quebec also has the right to reduce the load factor from 75 percent to 65 percent under the 1987 Contract a total of three times over the life of the contract. The Company can delay such reduction by one year under the 1987 Contract. During 2001, Hydro-Quebec exercised the first of these options for 2002, and the Company delayed the effective date of this exercise until 2003. The Company estimates that the net cost of Hydro-Quebec's exercise of its option will increase power supply expense during 2003 by approximately $0.4 million.

During 1994, the Company negotiated an arrangement with Hydro-Quebec that reduced 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 2001 to 2015 period, if documented drought conditions exist in Quebec. The period for completing the research and development purchase was subsequently extended to March 2003.

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 were 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		SCHEDUL
		(Dollars in thousands except per		
Capacity acquired. . . .		68 MW		46 M
Contract period.		1995-2015		1995-
Minimum energy purchase. (annual load factor)		75%		7
Annual energy charge . .	2002	$ 11,946		$ 8
estimated.	2003-2015	13,362	(1)	9
Annual capacity charge .	2002	$ 16,850		$11
estimated.	2003-2015	$ 17,122	(1)	$11
Average cost per KWh . .	2002	$ 0.065		$ 0
estimated.	2003-2015	$ 0.069	(2)	$ 0

(1) Estimated average includes load factor reduction to 65 percent in 2003
(2) Estimated average in nominal dollars levelized over the period indicated includes amortization of payments to Hydro-Quebec for the July 1994 Agreement

Under a separate arrangement established in December 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 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 1987 Contract and 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, 2002, Hydro-Quebec had purchased or called to purchase 458,000 MWh under option B.

In 2002, Hydro-Quebec exercised option A and called for deliveries to third parties at a net expense to the Company of approximately $3.0 million, including capacity charges.

In 2001, Hydro-Quebec exercised option A and option B, and called for deliveries to third parties at a net expense to the Company of approximately $6.5 million, including capacity charges.

In 2000, Hydro-Quebec called for deliveries to third parties at a net expense 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. The 9701 arrangement costs are currently being recovered in rates on an annual basis. The VPSB, in the Settlement Order stated, "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 the 9701 arrangement during the contract year ending October 31, 2002. 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 approximately $27.2 million. Future estimates could change by a material amount.

The Company believes that it is probable that Hydro-Quebec will call options A and B for 2003, and has purchased replacement power at a net cost of $4.7 million.

On April 17, 2001, an Arbitration Tribunal issued its decision in the arbitration brought by a group of Vermont electric companies and municipal utilities, known as the Vermont Joint Owners ("VJO"), against Hydro-Quebec for its failure to deliver electricity pursuant to the VJO/Hydro-Quebec power supply contract during the 1998 ice storm. The Company is a member of the VJO.

On July 23, 2001, the Company received approximately $3.2 million representing its share of refunded capacity payments from Hydro-Quebec. These proceeds reduced related deferred assets. At December 31, 2002, the remaining unamortized balance of unrecovered arbitration costs is approximately $0.9 million. We believe it is probable that this balance will ultimately be recovered in rates.

4. Morgan Stanley Contract - In February 1999, the Company entered into a contract with MS. In August 2002, the MS contract was modified and extended to December 31, 2006. The contract provides the Company 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.

The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. We anticipate that arrangements we make to manage power supply risks will be on average more costly than the expected cost of fuel during the periods being hedged because these arrangements would typically incorporate a risk premium.

L. DISCONTINUED OPERATIONS.

The Company sold or otherwise disposed of a significant portion of the operations and assets of NWR, which owned and invested in energy generation, energy efficiency, and wastewater treatment projects. The provisions for loss from discontinued operations reflect management's current estimate. At December 31, 2002, assets remaining include a wind power partnership investment, a note receivable from a regional hydro-power project, and notes receivable and equity investments with two wastewater treatment projects, one of which has risk factors that 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 residual operations earned $0.02 per share in 2002, primarily as a result of an adjustment to a reserve for warranty claims. The following illustrates the results and financial statement impact of discontinued operations during and at the periods shown:

	2002	2001	2000
(In thousands except per share)			

Revenues	$ 88	$ 156	$ 1,546
Gain (loss) on disposal	99	(182)	(6,549)
Net income (loss)	$ 99	$ (182)	$(6,549)
Net income (loss) per share-basic.	$ 0.02	$(0.03)	$ (1.19)
Proceeds from asset sales	$ -	$ -	$ 6,000
Total assets	$2,619	$3,697	$ 8,411
State income taxes	$ 19	$ (175)	$(1,064)
Federal income taxes	52	(550)	(3,349)
Investment tax credits	-	-	-
Income tax expense (benefit)	$ 71	$ (725)	$(4,413)

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.

2002 Quarter ended (Amounts in thousands except per share data)	MARCH	JUNE	SEPTEMBER	DECEMBER	TOTAL
Operating revenues	$68,866	$65,135	$ 73,477	$ 67,130	$274,608
Operating income	4,441	2,814	3,745	4,080	15,080
Net income-continuing operations	$ 3,354	$ 1,875	$ 3,042	$ 3,028	$ 11,299
Net income-discontinued operations	-	-	-	99	99
Net Income applicable to common stock	$ 3,354	$ 1,875	$ 3,042	$ 3,127	$ 11,398
Basic earnings per share from:					
Continuing operations	$ 0.59	$ 0.33	$ 0.53	0.57	$ 2.02
Discontinued operations	-	-	-	0.02	0.02
Basic earnings per share	$ 0.59	$ 0.33	$ 0.53	$ 0.59	$ 2.04
Weighted average common shares outstanding	5,691	5,711	5,723	5,333	5,592
Diluted earnings per share from:					
Continuing operations	$ 0.57	$ 0.32	$ 0.52	0.55	$ 1.96
Discontinued operations	-	-	-	0.02	0.02
Diluted earnings per share	$ 0.57	$ 0.32	$ 0.52	$ 0.57	$ 1.98
Weighted average common and common equivalent. shares outstanding	5,870	5,877	5,879	5,497	5,756

2001 Quarter ended (Amounts in thousands except per share data)	MARCH	JUNE	SEPTEMBER	DECEMBER	TOTA
Operating revenues	$74,796	$67,471	$ 76,051	$ 65,146	$283,4

Operating income	4,575	4,275	4,573	3,036	16,4
Net income-continuing operations	$ 2,914	$ 2,884	$ 3,387	$ 1,675	$ 10,8
Net loss-discontinued operations	-	(150)	-	(32)	(1
Net Income applicable to common stock.	$ 2,914	$ 2,734	$ 3,387	$ 1,643	$ 10,6
	=======	========	==========	==========	======
Basic earnings (loss) per share from:					
Continuing operations.	$ 0.52	$ 0.52	$ 0.60	$ 0.29	$ 1.
Discontinued operations.	-	(0.03)	-	-	(0.
Basic earnings per share	$ 0.52	$ 0.49	$ 0.60	$ 0.29	$ 1.
	=======	========	==========	==========	======
Weighted average common shares outstanding . .	5,588	5,615	5,644	5,672	5,6
Diluted earnings (loss) per share from:					
Continuing operations.	$ 0.51	$ 0.50	$ 0.58	$ 0.29	$ 1.
Discontinued operations.	-	(0.03)	-	-	(0.
Diluted earnings (loss) per share:	$ 0.51	$ 0.47	$ 0.58	$ 0.29	$ 1.
	=======	========	==========	==========	======
Weighted average common and common equivalent. shares outstanding	5,741	5,777	5,814	5,848	

	2000 Quarter ended				
	MARCH	JUNE	SEPTEMBER	DECEMBER	TOTAL
(Amounts in thousands except per share data)					
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)-continuing operations . . .	$ 3,449	$(4,375)	$ 1,961	$ (1,340)	$ (30
Net loss-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 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

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INDEPENDENT AUDITORS' REPORT
TO THE BOARD OF DIRECTORS OF
GREEN MOUNTAIN POWER CORPORATION:

We have audited the accompanying consolidated balance sheet of Green Mountain Power Corporation and subsidiaries (the Company) as of December 31, 2002, and the related consolidated statements of income, changes in common stock equity and cash flows for the year then ended December 31, 2002. The financial statements of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 and 2000 and for the years then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion which included an emphasis of matter paragraph on those financial statements in their report dated March 12, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain PowerCorporation and subsidiaries as of December 31, 2002 and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States.

Deloitte & Touche, LLP

Boston, Massachusetts
February 7, 2003

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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, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the 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, 2001 and 2000, and the consolidated results of its operations and cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

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

/s/ Arthur Andersen LLP
Boston, Massachusetts
March 12, 2002

The above report of Arthur Andersen LLP is a copy of the previously issued report, and the report has not been reissued by Arthur Andersen LLP.

Schedule II
GREEN MOUNTAIN POWER CORPORATION
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended December 31, 2002, 2001, and 2000

	Balance at Beginning of Period	Additions Charged to Cost & Expenses	Additions Charged to Other Accounts	Balance at End of / Ded
Injuries and Damages (1)				
2002	$12,064,548	325,000	134,505	2,
2001	13,382,713	212,555	312,229	1,
2000	10,129,130	111,667	3,193,383	
Bad Debt Reserve				
2002	575,890	-	-	
2001	425,890	150,000	575,890	
2000	390,495	35,395	-	

(1) Includes Pine Street Barge Canal reserves

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Green Mountain Power Corporation
Colchester, VT

We have audited the financial statements of Green Mountain Power Corporation as of December 31, 2002 and for the year then ended, and have issued our report thereon dated February 7, 2003; such report is included elsewhere in this Form 10-K. Our audit also included the financial statement schedules of Green Mountain Power Corporation, listed in Item 8. This financial statement schedule is the responsibility of the Corporation's management. Our responsibility is to express an opinion based on our audit. The financial statement schedule of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 and 2000 was audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on that schedule in their report dated March 12, 2002. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Boston, MA
February 7, 2003

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

We have audited, in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of Green Mountain Power Corporation included in this Form 10-K and have issued our report thereon dated March 12, 2002. Our report included an explanatory paragraph indicating that effective January 1, 2001, Green Mountain Power Corporation adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. 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 schedule 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.

/s/ Arthur Andersen LLP
Boston, Massachusetts
March 12, 2002

The above report of Arthur Andersen LLP is a copy of the previously issued report, and the report has not been reissued by Arthur Andersen LLP.

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

The July 17, 2002 decision to engage Deloitte & Touche LLP was made after careful consideration by the Green Mountain Power Corporation Board of Directors and senior management. The decision was not the result of any disagreement between Green Mountain Power and Arthur Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, for any periods audited and reported on by Arthur Andersen. Arthur Anderson's audit reports for the years ended December 31, 2001 and 2000 did not contain any qualification, modification, or disclaimers.

PART III

ITEMS 10, 11, 12 AND 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, Meetings, Committees and Other Relationships, "Section 16(a) Beneficial Ownership Reporting Compliance," "Executive Compensation and Other Information", "Compensation Committee Report on Executive Compensation", "Pension Plan Information and Other Benefits" 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 15, 2003. 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 2003.

ITEM 14. CONTROLS AND PROCEDURES

Within the 90 days prior to the filing date of this report, we carried out an evaluation, under the supervision and with the participation of our management, including Christopher L. Dutton, President and Chief Executive Officer and Robert J. Griffin, Treasurer and Controller (principal financial officer), of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-14 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, our President and Chief Executive Officer, and Treasurer and Controller (principal financial officer) concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to us (including our consolidated subsidiaries) required to be included in our periodic SEC filings.

There have been no significant changes in internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

Item 15(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 15(b) The following filings on Form 8-K were filed by the Company on the topic and date indicated:
A Form 8-K was filed on December 16, 2002 announcing the private placement of $42.0 million in long term bonds maturing in 2017 with an interest rate of 6.04 percent.

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

ITEM 14(A)3 AND ITEM 14(C). EXHIBITS SEC DOCKET
, INCORPORATED BY
EXHIBIT REFERENCE OR

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3-A . . . . RESTATED ARTICLES OF ASSOCIA
JUNE 6, 1991.
3-A-1 . . . . AMENDMENT TO 3-A ABOVE, DATE

3-A-2 . . . . AMENDMENT TO 3-A ABOVE, DATE

3-B . . . . BY-LAWS OF THE COMPANY, AS A
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4-B-1 . . . . INDENTURE OF FIRST MORTGAGE
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4-B-3 . . . . SECOND SUPPLEMENTAL INDENTUR
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4-B-4 . . . . THIRD SUPPLEMENTAL INDENTURE
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4-B-5 . . . . FOURTH SUPPLEMENTAL INDENTUR
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4-B-6 . . . . FIFTH SUPPLEMENTAL INDENTURE
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4-B-7 . . . . SEVENTH SUPPLEMENTAL INDENTU
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4-B-8 . . . . EIGHTH SUPPLEMENTAL INDENTUR
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4-B-9 . . . . NINTH SUPPLEMENTAL INDENTURE
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4-B-11. . . . . ELEVENTH SUPPLEMENTAL INDENT
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4-B-15. . . . . FIFTEENTH SUPPLEMENTAL INDEN
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4-B-16. . . . . SIXTEENTH SUPPLEMENTAL INDEN
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4-B-17. . . . . REVISED FORM OF INDENTURE AS
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4-B-18. . . . . CREDIT AGREEMENT BY AND AMON
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TRUST COMPANY, FLEET NATIONAL BANK, AND FLEET
NATIONAL BANK, AS AGENT
4-B-18(A) . . . . AMENDMENT TO EXHIBIT 4-B-18

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10-A. . . . . FORM OF INSURANCE POLICY ISS
INSURANCE COMPANY, WITH RESPECT TO
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10-B-1. . . . . FIRM POWER CONTRACT DATED SE
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1958; NOVEMBER 15, 1958; OCTOBER 1, 1960 AND
FEBRUARY 1, 1964.
10-B-2. . . . . POWER CONTRACT, DATED FEBRUA
AND VERMONT YANKEE NUCLEAR POWER CORPORATION.
10-B-3. . . . . AMENDMENT, DATED JUNE 1, 197
BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR

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10-B-3(A) . . . . AMENDMENT, DATED APRIL 15, 1
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10-B-3(B) . . . . ADDITIONAL POWER CONTRACT, D
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10-B-4. . . . . CAPITAL FUNDS AGREEMENT, DAT
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10-B-5. . . . . AMENDMENT, DATED MARCH 12, 1
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10-B-8. . . . . AMENDMENT TO EXHIBIT 10-B-7,
10-B-9. . . . . THREE-PARTY TRANSMISSION AGR
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10-B-14 . . . . AGREEMENT WITH CENTRAL MAINE
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10-B-15 . . . . NEW ENGLAND POWER POOL AGREE
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10-B-16 . . . . BULK POWER TRANSMISSION CONT
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10-B-17 . . . . AMENDMENT TO EXHIBIT 10-B-16
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10-B-21 . . . . AGREEMENT DATED OCTOBER 1, 1
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10-B-28 . . . . CONTRACT DATED FEBRUARY 1, 1
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10-B-30 . . . . BULK POWER PURCHASE CONTRACT
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10-B-33 . . . . AGREEMENT AMENDING NEW ENGLA
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10-B-34 . . . . PHASE I TRANSMISSION LINE SU
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NO. 1 DATED AS OF JUNE 1, 1982, BETWEEN
VETCO AND PARTICIPATING NEW ENGLAND UTILITIES
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FACILITIES OF TRANSMISSION INTERCONNECTION
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10-B-35 . . . . PHASE I TERMINAL FACILITY SU
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BETWEEN NEW ENGLAND AND HYDRO-QUEBEC.

10-B-36 . . . . AGREEMENT WITH RESPECT TO US
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10-B-39 . . . . VERMONT PARTICIPATION AGREEM
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BETWEEN VELCO AND PARTICIPATING VERMONT
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10-B-40 . . . . VERMONT ELECTRIC TRANSMISSIO
CAPITAL FUNDS AGREEMENT DATED AS OF JULY 15,
1982, BETWEEN VETCO AND VELCO FOR VELCO TO PROVIDE
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OF THE TRANSMISSION INTER-CONNECTION BETWEEN NEW
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10-B-41 . . . . VETCO CAPITAL FUNDS SUPPORT
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10-B-42 . . . . ENERGY BANKING AGREEMENT DAT
AMONG HYDRO-QUEBEC, VELCO, NEET AND PARTI-
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THROUGH THE NEPOOL MANAGEMENT COMMITTEE FOR
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10-B-43 . . . . INTERCONNECTION AGREEMENT DA
BETWEEN HYDRO-QUBEC AND PARTICIPATING NEW
ENGLAND UTILITIES ACTING BY AND THROUGH THE
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10-B-44 . . . . ENERGY CONTRACT DATED MARCH
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UTILITIES ACTING BY AND THROUGH THE NEPOOL
MANAGEMENT COMMITTEE FOR PURCHASE OF
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10-B-50 . . . . AGREEMENT FOR JOINT OWNERSHI
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BETWEEN CERTAIN ELECTRIC DISTRIBUTION
COMPANIES, INCLUDING THE COMPANY.

10-B-51 . . . . HIGHGATE OPERATING AND MANAG
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VERMONT ELECTRIC-UTILITY COMPANIES, INCLUDING
THE COMPANY.

10-B-52 . . . . ALLOCATION CONTRACT FOR HYDR
DATED JULY 25, 1984, BETWEEN THE STATE OF
VERMONT AND VARIOUS VERMONT ELECTRIC UTILITIES,
INCLUDING THE COMPANY.

10-B-53 . . . . HIGHGATE TRANSMISSION AGREEM
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PROJECT AND VARIOUS VERMONT ELECTRIC
DISTRIBUTION COMPANIES.

10-B-61 . . . . AGREEMENTS ENTERED IN CONNEC
OF THE NEPOOL/HYDRO-QUEBEC + 450 KV HVDC
TRANSMISSION INTERCONNECTION.

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10-B-62 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  AGREEMENT BETWEEN UNITIL POW
  COMPANY TO SELL 23 MW CAPACITY AND ENERGY FROM
  STONY BROOK INTERMEDIATE COMBINED CYCLE UNIT.
10-B-68 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  FIRM POWER AND ENERGY CONTRA
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  VERMONT UTILITIES, INCLUDING THE COMPANY, FOR
  THE PURCHASE OF FIRM POWER FOR UP TO THIRTY YEARS.
10-B-69 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  FIRM POWER AGREEMENT DATED A
  BETWEEN ONTARIO HYDRO AND VERMONT DEPARTMENT OF
  PUBLIC SERVICE.
10-B-70 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  FIRM POWER AND ENERGY CONTRA
  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(A). . . . . . . . . . . . . . . . . . . . . . . . . . .  AMENDMENT TO 10-B-70.

10-B-71 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  INTERCONNECTION AGREEMENT DA
  FEBRUARY 23, 1987, BETWEEN THE VERMONT JOINT
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10-B-72 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  PARTICIPATION AGREEMENT DATE
  BETWEEN HYDRO-QUEBEC 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(A). . . . . . . . . . . . . . . . . . . . . . . . . . .  RESTATEMENT OF THE PARTICIPA
  AS EXHIBIT 10-B-72 ON FORM 10-Q FOR JUNE 1988.
10-B-77 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  FIRM POWER AND ENERGY CONTRA
  1988, BETWEEN HYDRO-QUEBEC AND PARTICIPATING
  VERMONT UTILITIES, INCLUDING THE COMPANY, FOR THE
  PURCHASE OF UP TO 54 MW OF FIRM POWER AND ENERGY.
10-B-78 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  TRANSMISSION AGREEMENT DATED
  BETWEEN THE COMPANY AND NIAGARA MOHAWK POWER
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10-B-81 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  SALES AGREEMENT DATED MAY 24
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  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
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  PUBLIC SERVICE OR FEDERAL PREFERENCE POWER.
10-B-82 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  SALES AGREEMENT DATED JULY 1
  NORTHFIELD ELECTRIC DEPARTMENT AND THE COMPANY. . . . . . . . .  JUNE 1989
  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-85 . . . . . . . . . . . . . . . . . . . . . . . . . . . .  POWER PURCHASE AND SALE AGRE
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10-B-90 . . . . PURCHASE POWER AGREEMENT BET
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10-B-92 . . . . AMENDMENT TO POWER PURCHASE
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3-B . . . . FEBRUARY 10, 1997.	3-B	FORM 10-K 1996 (1
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4-B-5 . . . . OCTOBER 1, 1969.	4-B-5	2-
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4-B-8 . . . . DECEMBER 1, 1979.	4-A-8	2-
4-B-9 . . . . JULY 15, 1985.	4-B-9	2-
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4-B-13. . . . . MARCH 1, 1992.	4-B-13	FORM 10-K 1991 (1
4-B-14. . . . . NOVEMBER 1, 1993.	4-B-14	FORM 10-K 1993 (1
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4-B-16. . . . . DECEMBER 1, 1995.	4-B-16	FORM 10-K 1995 (1
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4-B-18. . . . . THE BANK OF NOVA SCOTIA, STATE STREET BANK AND	4-B-18	FORM 10-K 1997 (1

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  AND SUPPLEMENTS  THERETO DATED SEPTEMBER 19,
  1958; NOVEMBER 15, 1958;  OCTOBER 1, 1960 AND
  FEBRUARY 1, 1964.
10-B-2. . . . . . . . . . . . . . . . . . . . . . . . . . .         13-D               2-
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10-B-3. . . . . . . . . . . . . . . . . . . . . . . . . . .       13-F-1               2-
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  POWER CORPORATION.
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10-B-3(B) . . . . . . . . . . . . . . . . . . . . . . . . .    10-B-3(B)               33
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10-B-4. . . . . . . . . . . . . . . . . . . . . . . . . . .         13-E               2-
  1968, BETWEEN THE COMPANY AND VERMONT
  YANKEE NUCLEAR POWER CORPORATION.
10-B-5. . . . . . . . . . . . . . . . . . . . . . . . . . .         13-F               2-
  FUNDS AGREEMENT BETWEEN THE COMPANY AND
  VERMONT YANKEE NUCLEAR POWER CORPORATION.
10-B-6. . . . . . . . . . . . . . . . . . . . . . . . . . .       10-B-6               2-
  COMPANY FOR ITS PROPORTIONATE SHARE OF THE OBLIGATIONS
  OF VERMONT YANKEE NUCLEAR POWER CORPORATION
  UNDER A $40 MILLION LOAN ARRANGEMENT.
10-B-7. . . . . . . . . . . . . . . . . . . . . . . . . . .         13-I               2-
  VELCO AND CENTRAL VERMONT PUBLIC SERVICE
  CORPORATION DATED NOVEMBER 21, 1969.
10-B-8. . . . . . . . . . . . . . . . . . . . . . . . . . .       10-B-8               2-
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  SERVICE CORPORATION, DATED NOVEMBER 21, 1969.
10-B-10 . . . . . . . . . . . . . . . . . . . . . . . . . .      10-B-10               2-
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10-B-16 . . . . . . . . . . . . . . . . . . . . . . . . . .         13-V          2-49697
  COMPANY AND VELCO DATED JUNE 1, 1968.
10-B-17 . . . . . . . . . . . . . . . . . . . . . . . . . .       13-V-I          2-49697
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  AMENDED OCTOBER 1, 1977, AND RELATED
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10-B-21 . . . . . . . . . . . . . . . . . . . . . . . . . .      10-B-21          33-8164
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  THE SALE OF FIRM POWER AND ENERGY BY THE POWER
  AUTHORITY OF THE STATE OF NEW YORK TO THE
  VERMONT PUBLIC SERVICE BOARD.
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  1976, BETWEEN VELCO AND THE COMPANY.
10-B-33 . . . . . . . . . . . . . . . . . . . . . . . . . . . .       10-B-33         33-8164
  DATED AS OF DECEMBER 1, 1981, PROVIDING FOR USE OF
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10-B-34 . . . . . . . . . . . . . . . . . . . . . . . . . . . .       10-B-34         33-8164
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  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
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10-B-35 . . . . . . . . . . . . . . . . . . . . . . . . . . . .       10-B-35         33-8164
  DATED AS OF DECEMBER 1, 1981, AND AMENDMENT
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  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-QUEBEC.
10-B-36 . . . . . . . . . . . . . . . . . . . . . . . . . . . .       10-B-36         33-8164
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  AMONG PARTICIPATING NEW ENGLAND UTILITIES
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  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-QUEBEC.
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10-D-32. . . . . . . . . . . . . . . . . . . . . . . . .  FORM 10-K 2001
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10-D-34. . . . . . . . . . . . . . . . . . . . . . . . .  FORM 10-K 2001
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Exhibit 23.1

Independent Auditors' Consent

We consent to the incorporation by reference in Registration Statement Nos. 333-38722, 333-39822 and 333-42356 of Green Mountain Power Corporation of our report dated February 7, 2003 relating to the consolidated financial statements of Green Mountain Power Corporation as of and for the year ended December 31, 2002 appearing in this Annual Report on Form 10-K of Green Mountain Power Corporation for the year ended December 31, 2002.

/s/DELOITTE & TOUCHE LLP

March 21, 2003

Exhibit 23.2

Statement of Company Concerning Consent of Arthur Andersen LLP

Prior to 2002, Arthur Andersen LLP was our independent accountants. As a result of the 2002 closing of the applicable Arthur Andersen LLP offices, we were unable to obtain the consent of Arthur Andersen LLP to the incorporation by reference of their report in this Form 10-K with respect to our financial statements as of December 31, 2001, and for the fiscal years ended December 31, 2001 and 2000. We have dispensed with the requirement under Section 7 of the Securities Act of 1933, as amended (the "Securities Act"), to file their consent in reliance on Rule 437(a) promulgated under the Securities Act. Because Arthur Andersen LLP has not consented to the incorporation by reference of their report in this Form 10-K, a person who purchases the Company's securities in reliance upon such report may be unable to recover against Arthur Andersen LLP under Section 11 of the Securities Act for any untrue statements of a material fact contained in the financial statements audited by Arthur Andersen LLP incorporated by reference or any omissions to state a material fact required to be stated therein.

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EXHIBIT 24

POWER OF ATTORNEY

We, the undersigned directors of Green Mountain Power Corporation, hereby severally constitute Christopher L. Dutton, Mary G. Powell, 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, 2002, 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)	March 6, 2003
/s/Nordahl L. Brue Nordahl L. Brue	Chairman of the Board	March 13, 2003
/s/Elizabeth A. Bankowski Elizabeth A. Bankowski	Director	March 11, 2003
/s/William H. Bruett William H. Bruett	Director	March 17, 2003
/s/Merrill O. Burns Merrill O. Burns	Director	March 14, 2003
/s/Lorraine E. Chickering Lorraine E. Chickering	Director	March 12, 2003
/s/John V. Cleary John V. Cleary	Director	March 10, 2003
/s/David R. Coates David R. Coates	Director	March 4, 2003
/s/Euclid A. Irving Euclid A. Irving	Director	March 10, 2003

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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

Date: March 24, 2003

By: /s/ Christopher L. Dutton

Christopher L. Dutton, President and Chief Executive Officer

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, Chief Executive Officer, and Director	March 24, 2003
/s/ Mary G. Powell_______ Mary G. Powell	Chief Operating Officer, Senior Vice President	March 24, 2003
/s/ Robert J. Griffin Robert J. Griffin	Controller, Treasurer (Principal Accounting Officer)	March 24, 2003
*Nordahl L. Brue)	Chairman of the Board	
*Elizabeth Bankowski		
*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 24, 2003

Christopher L. Dutton
(Attorney - in - Fact)

I, Christopher L. Dutton, certify that:

1. I have reviewed this annual report on Form 10-K of Green Mountain Power Corporation;

2. Based on my knowledge, this annual report does not contain any untrue

statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or person performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses

Date: March 24, 2003

/s/Christopher L. Dutton

Christopher L. Dutton, Chief Executive Officer and President

I, Robert J. Griffin, certify that:
1. I have reviewed this annual report on Form 10-K of Green Mountain Power Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or person performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses

Date: March 24, 2003

/s/Robert J. Griffin

Robert J. Griffin, Treasurer and Controller (Principal Financial Officer)