GREEN MOUNTAIN POWER CORP
Form 10-K
March 12, 2004

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, 2003
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 ___

THE AGGREGATE MARKET VALUE OF THE VOTING STOCK HELD BY NON-AFFILIATES OF THE REGISTRANT AS OF FEBRUARY 27, 2004, WAS APPROXIMATELY $132,657,931 BASED ON THE CLOSING PRICE OF $26.27 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 FEBRUARY 27, 2004, WAS

5,049,788

DOCUMENTS INCORPORATED BY REFERENCE

The Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 20, 2004, 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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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 2003 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 service territory with approximately one quarter of Vermont's population. We serve approximately 89,000 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, 2003 were as follows:

* 26.9 percent from residential customers;
* 26.4 percent from small commercial and industrial customers;
* 17.1 percent from large commercial and industrial customers;
* 28.1 percent from sales to other utilities; and
* 1.5 percent from other sources.

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

During 2003, our energy resources for retail and wholesale sales of electricity, excluding purchases made pursuant to the contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") discussed under MD and A-Power Contract Commitments, were obtained as follows:

* 35.4 percent from hydroelectric sources (28.1 percent Hydro-Quebec, 4.5 percent Company-owned, and 2.8 percent independent power producers);
* 37.4 percent from a nuclear generating source (the Entergy Nuclear Vermont Yankee, LLC ("ENVY") nuclear plant described below);
* 3.5 percent from wood;
* 1.3 percent from natural gas;
* 2.7 percent from oil; and
* 0.5 percent from wind.

The remaining 19.2 percent was purchased on a short-term basis from other utilities through the Independent System Operator of New England ("ISO-NE" or "ISO New England"), formerly the New England Power Pool ("NEPOOL").

In 2003, we estimate that we purchased or generated in excess of 90.0 percent of our energy resources to satisfy our retail and wholesale sales of electricity under long-term arrangements, including the Morgan Stanley Contract. Remaining retail and wholesale sales were met through short-term market purchases and represent volumetric differences between purchase commitments and our customers' retail demand. 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 ENVY. We have a 33.6 percent equity interest in Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VY"), which has a long-term power supply contract with ENVY 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 United States. The ISO-NE was created to manage the operations of NEPOOL, effective May 1, 1999. ISO-NE operates a market for all New England states 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, to replace energy repurchased by Hydro-Quebec under an arrangement negotiated in 1997 and to replace power not delivered under our contracts and entitlements due to outages, curtailments or other events that result in reduced deliveries. 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 ENVY 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, 2003	2002	2001	2000
Total capability (MW)	393.9	406.9	408.0	41
Net system peak	330.2	342.0	341.2	32
Reserve (MW).	63.7	64.9	66.8	8
Reserve % of peak	19.3%	19.0%	19.6%	2

Net Production (MWH**)				
Hydro	838,855	901,998	951,146	1,053,
Wind.	10,828	11,458	12,135	12,
Nuclear	884,585	771,781	736,420	803,
Conventional steam.	2,524,233	2,431,115	2,670,249	2,704,
Internal combustion	12,603	4,090	18,291	35,
Combined cycle.	68,488	81,362	72,653	73,
Total production.	4,339,592	4,201,804	4,460,894	4,682,
Less non-firm sales to other utilities.	2,284,003	2,104,172	2,365,809	2,573,
Production for firm sales	2,055,589	2,097,632	2,095,085	2,108,
Less firm sales and lease transmissions.	1,937,376	1,951,959	1,956,232	1,954,
Losses and company use (MWH).	118,213	145,673	138,853	153,
Losses as a % of total production	2.72%	3.47%	3.11%	3
System load factor (***).	71.1%	70.0%	70.1%	7
Net Production (% of Total)				
Hydro	19.3%	21.5%	21.3%	2
Wind.	0.2%	0.3%	0.3%	
Nuclear	20.4%	18.3%	16.5%	1
Conventional steam.	58.2%	57.9%	59.9%	5
Internal combustion	0.3%	0.1%	0.4%	
Combined cycle.	1.6%	1.9%	1.6%	
Total	100.0%	100.0%	100.0%	10
Sales and Lease Transmissions(MWH)				
Residential - GMPC.	581,047	553,294	549,151	558,
Commercial & industrial - small	703,036	695,504	691,029	704,
Commercial & industrial - large	645,271	689,618	710,944	683,
Other	4,986	9,773	2,030	6,
Total retail sales and lease transmissions. . . .	1,934,340	1,948,189	1,953,154	1,952,
Sales to Municipals & Cooperatives (Rate W) . . .	3,036	3,770	3,078	2,
Total Requirements Sales.	1,937,376	1,951,959	1,956,232	1,954,
Other Sales for Resale.	2,284,003	2,104,172	2,365,809	2,573,
Total sales and lease transmissions(MWH)	4,221,379	4,056,131	4,322,041	4,528,
Average Number of Electric Customers				
Residential	74,693	73,861	73,249	72,
Commercial and industrial small	13,344	13,165	12,976	12,
Commercial and industrial large	25	29	30	
Other	65	65	65	
Total.	88,127	87,120	86,320	85,
Average Revenue Per KWH (Cents)				
Residential including lease revenues.	12.98	12.96	13.33	12
Commercial & industrial - small	10.40	10.44	10.90	10
Commercial & industrial - large	7.41	7.31	7.70	6
Total retail including lease.	10.22	10.09	10.44	9
Average Use and Revenue Per Residential Customer				
KWh's including lease transmissions	7,779	7,491	7,497	7,
Revenues including lease revenues	$ 1,010	$ 971	$ 999	$

(*) 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", or the "Board"), which extends to retail rates, services and facilities, securities issues and various other matters. The separate Vermont Department of Public Service (the "Department," or the "DPS"), 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 the public advocate 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 certain loads. All such agreements must be approved by the VPSB. 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 2003.

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 2003.

On July 17, 1997, the FERC approved our Open Access Transmission Tariff, and on August 30, 1997 we filed our compliance 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 have not experienced 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. The amounts appropriated are not material.

The re-licensing 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 late 2004. When repairs are complete, we expect the project to be re-licensed for a 30-year term. 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 August 14, 2003, we filed with the VPSB and the Department an integrated resource plan pursuant to Vermont Statute 30 V.S.A. 218c. That filing is pending before the VPSB.

RECENT RATE DEVELOPMENTS

The VPSB issued an order on December 22, 2003 approving the Company's 2003 Rate Plan (the "2003 Rate Plan"), jointly proposed by the Company and the Department. Principal terms of the 2003 Rate Plan include:

Allows the Company to raise rates 1.9 percent, effective January 1, 2005; and 0.9 percent effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates.

Allows the Company the opportunity to file for rate increases during the period from January 1, 2003 to January 1, 2007 if the Company experiences extraordinary events, such as repair costs due to an ice storm or other natural disaster.

Reduces the Company's allowed return on equity from 11.25 percent to 10.5 percent for the period beginning January 1, 2003 to January 1, 2007.

Approves a three-year economic development agreement for IBM, as long as IBM does not reduce employment by more than five percent during the period.

Provides for recovery of various regulatory assets, including the remediation of the Pine Street environmental superfund site in Burlington, VT.

SINGLE CUSTOMER DEPENDENCE

The Company had one major retail customer, IBM, metered at two locations that accounted for 16.6 percent, 17.3 percent and 19.2 percent of the Company's retail operating revenues in 2003, 2002 and 2001, respectively. No other retail customer accounted for more than 1.0 percent of our revenue during the past three years.

IBM has reduced its Vermont workforce by approximately 2,500 since 2001, to a level of approximately 6,000 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 that would result from a hypothetical shutdown of the IBM facility to be in the range of five to eight percent, inclusive of projected declines in sales to other 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.

In March 2002, voters in the Town of Rockingham, Vermont ("Rockingham") approved an article authorizing Rockingham to create a municipal utility and to acquire the electric distribution systems of the Company and/or Central Vermont Public Service Corporation located within the Rockingham. In November 2003, Rockingham notified the Company that the town intended to initiate proceedings before the town selectboard to condemn the Company's distribution and associated property located within the town. The Company sought and obtained in December 2003 a preliminary injunction from the State Superior Court prohibiting the town from proceeding with condemnation before the selectboard. The Company successfully argued that Vermont law required Rockingham to pursue any such municipalization effort by petition to the VPSB, which is required to determine both the fair value of any assets subject to municipalization and the amount of damages to the utility caused by severance of the property subject to municipalization. The preliminary injunction remains in effect and Rockingham has not filed any petition with the VPSB seeking to municipalize assets. 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. 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 other 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 could potentially 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.

There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont. Legislation has been introduced in the Vermont legislature that would permit (but not require) the Company to negotiate with individual customers to permit such customers to procure their own electric power supply requirements, subject to VPSB approval. We cannot predict whether this legislation will be enacted. If enacted, the Company would not negotiate any such arrangement unless, in our estimation, the arrangement assured the Company of full recovery of any resulting stranded costs and that the Company's financial condition would not otherwise be adversely affected.

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

CONSTRUCTION AND CAPITAL REQUIREMENTS

Our capital expenditures for 2001 through 2003 and projected for 2004 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. 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. ("Morgan Stanley"). In August 2002, the Morgan Stanley 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 Morgan Stanley Contract, see Note K of Notes.

We generated, purchased or transmitted 2,364,130 MWh of energy for retail and requirements wholesale customers for the twelve months ended December 31, 2003. The corresponding maximum one-hour integrated demand during that period was 330.2 MW on August 5, 2003. This compares to the previous all-time peak of 342.0 MW on August 15, 2002. 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 12/31/2003		Capacity At time of of annual peak	
	MWH	percent	KW	percent
Wholly-owned plants:				
Hydro	107,406	4.5%	32,870	8.9%
Diesel and Gas Turbine.	12,603	0.5%	50,623	13.6%
Wind.	10,828	0.5%	480	0.1%
Jointly-owned plants:				
Wyman #4.	12,030	0.5%	6,968	1.9%
Stony Brook I	43,833	1.9%	27,113	7.3%
McNeil.	25,328	1.1%	6,443	1.7%
Long Term Purchases:				
Vermont Yankee/ENVY	884,585	37.4%	100,554	27.1%
Hydro Quebec.	664,225	28.1%	114,174	30.8%
Stony Brook I	24,655	1.0%	12,382	3.3%
Other:				
Independent Power Producers . .	125,465	5.3%	19,286	5.2%
NEPOOL and Short-term purchases	453,172	19.2%	400	0.1%
Net Own Load.	2,364,130	100.0%	371,293	100.0%

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Vermont Yankee.

On July 31, 2002, Vermont Yankee completed the sale of its nuclear power plant to "ENVY". In addition to the sale of the generating plant, the transaction calls for ENVY, 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.

Prices under the Power Purchase Agreement between VY and ENVY (the "PPA") range from $39 to $45 per megawatt-hour for the period beginning January 2003. 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 ENVY plant.

Prior to the sale of the VY plant to ENVY, the 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. The Company expects to amortize (recover) these costs beginning in 2005 under the Company's 2003 Rate Plan. The Company received a credit of approximately $600,000 from VY and has requested permission from the VPSB to apply this credit to reduce the $2.0 million regulatory asset. Our ownership share of VY has increased from approximately 19.0 percent last year to approximately 33.6 percent currently, due to VY's purchase of certain minority shareholders' interests. VY's primary role consists of administering its power supply contract with ENVY and its contracts with VY's present sponsors. Our entitlement to energy produced by the ENVY nuclear plant has remained at 20 percent of plant production.

Under our Capital Funds Agreement with VY, we are 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 ENVY power is unavailable, the costs of replacement power occasionally exceed those costs that we would have incurred for ENVY power purchased from Vermont Yankee. Replacement power is available to us from the ISO-NE and through contractual arrangements with other utilities. Replacement power costs can adversely affect cash flow, and, unless deferred and/or recovered in rates, such costs could 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 and recovery of such costs.

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

During the year ended December 31, 2003, we used 884,585 MWh of Vermont Yankee energy (supplied by ENVY) representing 37.4 percent of the net electricity generated and purchased ("net power supply") by the Company. The average cost of Vermont Yankee electricity in 2003 was $0.043 per kWh.

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 approximately 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;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 originate at the Des Cantons Substation on the Hydro-Quebec system near Sherbrooke, Canada and traverse a portion of eastern Vermont and extend to a converter terminal located in Comerford, New Hampshire. VETCO was formed to construct and operate the portion of Phase I within the United States. 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. 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. The participants in this project, 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, 2003, the present value of the Company's obligation was approximately $4,647,000. The Company's projected future minimum payments under the Phase II support agreements are approximately $387,000 for each of the years 2004-2008 and an aggregate of $2,712,000 for the years 2009-2015.

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 in such companies. 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, 2003, the capital structure of such corporations was approximately 44 percent common equity and 56 percent long-term debt. See Note B and Note J of Notes.

Hydro-Quebec

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 (the "VJO Contract"). Under these two schedules, we purchase 114.2 MW from Hydro-Quebec. In November 1996, we entered into an arrangement (the "9701 arrangement") with Hydro-Quebec under which Hydro-Quebec paid $8,000,000 to the Company in exchange for certain power purchase options. See Item 7. MD and A - Power Supply Expenses, Power Contract Commitments and Note K of Notes.

During 2003, we used 392,990 MWh under Schedule B, and 271,235 MWh under Schedule C3 of the VJO Contract, representing 28.1 percent of our net power supply. The average cost of Hydro-Quebec electricity in 2003 was approximately $0.07 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 power on short notice and generally for brief periods of time when required to balance electricity supply with demand. Opportunity purchases are also arranged when it is possible to purchase power for less than it would cost us to generate the power with our own sources. Purchases may also help us save on replacement power costs during an outage of one of our base load sources. Opportunity sale prices are generally set so as to recover all of the forecasted fuel or production costs and to recover some, if not all, associated capacity costs. During 2003, the Company purchased 453,172 MWh representing 19.2 percent of the Company's net power supply at an average cost of $0.06 per kWh.

During 2002, the FERC accepted ISO-NE's request to implement a SMD governing wholesale energy sales in New England. ISO-NE 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. ISO-NE and NEPOOL have committed to facilitation of a stakeholder process to examine alternative pricing options, including alternatives to nodal pricing, and to file their report with FERC in July 2004. We believe that nodal pricing could result in a material adverse impact on our power supply or transmission costs, if adopted.

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 2003, we used 68,488 MWh from this plant representing 2.9 percent of our net power supply at an average cost of $0.087 per kWh. See Notes I and K 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 2003, we used 12,030 MWh from this unit representing 0.5 percent of our net power supply at an average cost of $0.06 per kWh, based only on operation, maintenance, and fuel costs incurred during 2003. See Note I of Notes.

McNeil Station. The J.C. McNeil station (the "McNeil Plant"), 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 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 2003, we used 25,328 MWh from this unit representing 1.1 percent of our net power supply at an average cost of $0.055 per kWh, based only on operation, maintenance, and fuel costs incurred during 2003. 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-appointed purchasing agent under a variety of long-term 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's 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 2003 was approximately 34.03 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 2003, through our direct contracts and VEPPI, we purchased 125,465 MWh of qualifying facilities production representing 5.3 percent of our net power supply at an average cost of $0.122 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 2003, Company owned hydroelectric plants produced 107,406 MWh, representing 4.5 percent of our net power supply at an average cost of $0.03 per kWh based on operating and maintenance expenses, excluding depreciation expense and amortization of licensing costs. 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 the New York Power Authority 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 2003, our retail and requirements wholesale sales were provided by the following fuel sources:

* 35.4 percent from hydroelectric sources (28.1 percent Hydro-Quebec, 4.5 percent Company-owned, and 2.8 percent independent power producers;
* 37.4 percent from a nuclear generating source (the ENVY nuclear plant);
* 3.5 percent from wood;
* 1.3 percent from natural gas;
* 2.7 percent from oil;
* 0.5 percent from wind; and
* 19.2 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 2003. None 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 330,503 tons of wood chips and mill residue, 423,310 gallons of fuel oil, and 31 million cubic feet of natural gas in 2003. The McNeil plant, assuming any needed regulatory approvals are obtained, is forecasting 2004 consumption of wood chips to be 400,000 tons, fuel oil of 70,000 gallons and natural gas consumption of 36 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 expenditures 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 2003, the project produced 10,828 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, 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, 2003, the Company had 196 employees, exclusive of temporary employees. The Company considers its relations with employees to be excellent.

ENERGY EFFICIENCY

In 2003, 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. A charge per KW and per KWH is applied. The purpose of these charges is to apply equal efficiency charges across Vermont to customers with similar usage, regardless of their local utility rates. The charge represents two to three percent of each customer's total electric bill.

The funds we collect are remitted to a fiscal agent representing the State of Vermont.

RATE DESIGN

The Company seeks to design rates to encourage efficient electrical use. Since 1976, we have offered optional time-of-use rates for residential and commercial customers. Currently, approximately 1,800 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. At December 31, 2003, approximately 1,700 of the Company's largest customers, comprising approximately 51 percent of retail revenues, received service on mandatory time-of-use rates. As a result of the VPSB approval of the 2003 Rate Plan, the Company will file with the VPSB a new fully-allocated cost of service study and rate re-design, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design will be subject to VPSB approval and is not expected to adversely affect operating results.

DISPATCHABLE AND INTERRUPTIBLE SERVICE CONTRACTS

In 2003, we had 27 dispatchable power contracts: 22 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 business in the process of completing dissolution. For information regarding our remaining unregulated businesses, see Note A and Note L of Notes.

EXECUTIVE OFFICERS

The names, ages, and positions of our Executive Officers, in alphabetical order, as of March 15, 2004 are:

Christopher L. Dutton 55

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 47

Chief Financial Officer since December 2003. Vice President since July 2003. Treasurer since February 2002. Controller from October 1996 to December 2003. Manager of General Accounting from 1990 to 1996.

Walter S. Oakes 57

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 43

Senior Vice President-Chief Operating Officer since April 2001. Senior Vice President-Customer and Organizational Development from December 1999 to April 2001. 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, Ms. Powell was President of HRworks, Inc., a human resources management firm, from January 1997 to March 1998.

Donald J. Rendall 48

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

Stephen C. Terry 61

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.

The Board of Directors of the Company and its wholly owned subsidiaries, as appropriate, elects officers for one-year terms to 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 67.6 MW and an estimated aggregate claimed capability of 61.2 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:

* 33.6 percent of the outstanding common stock of Vermont Yankee and, through its contract with ENVY, we are entitled to 20.0 percent (106.2 MW of a total 531 MW) of the capacity of the ENVY nuclear generating 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, 2003, approximately 2 miles of 115 kV transmission lines, 10 miles of 69 kV transmission lines, 5 miles of 44 kV transmission lines, 244 miles of 34.5 kV transmission lines, and 2 miles of 13.8 kV transmission lines. Our distribution system included approximately 2,573 miles of overhead lines of 2.4 to 34.5 kV and 420 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 905,000 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.

Winter
Capability

	Location	Name	Fuel	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 Turbine	Berlin, VT	Berlin #5	Oil	56.6	
Turbine	Colchester, VT	Gorge #16	Oil	16.1	
Wind.	Searsburg, VT	Searsburg	Wind	5.9	
Jointly Owned					
Steam	Yarmouth, ME	Wyman #4	Oil	7.1	
Steam	Burlington, VT	McNeil	Wood/Gas	6.6	(2)
Combined.	Ludlow, MA	Stony Brook #1	Oil/Gas	31.0	
Total Winter Capability				167.2	

(1) Reservoir has been drained, dam awaiting repairs by the State of Vermont.
(2) 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.

CORPORATE HEADQUARTERS

Our headquarters and main service center are located in Colchester Vermont, one of the most rapidly growing areas of our service territory.

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 - Other Risks, 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 2002 and 2003:

HIGH	LOW

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
2003		
First Quarter.	$21.19	$19.02
Second Quarter	21.78	20.00
Third Quarter.	22.72	20.06
Fourth Quarter	23.84	21.98

The number of common stockholders of record as of February 18, 2004 was approximately 5,119.

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2002	$ 0.1375	$ 0.1375	$ 0.1375	$ 0.1900
2003	$ 0.1900	$ 0.1900	$ 0.1900	$ 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 increased its dividend from an annual rate of $0.76 per share to $0.88 per share during February 2004, and intends to increase the dividend in a measured consistent manner until the payout ratio falls between 50 percent and 70 percent of anticipated earnings, so long as financial and operating results permit. We believe this payout ratio to be consistent with that of other electric utilities having similar risk profiles.

ITEM 6. SELECTED FINANCIAL DATA

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31,

	2003	2002	2001
In thousands, except per share data			
Operating Revenues.	$280,470	$274,608	$283,464
Operating Expenses.	265,164	259,528	267,005
Operating Income.	15,306	15,080	16,459
Other Income			
AFUDC - equity.	387	233	210
Other	1,692	2,252	2,163
Total other income.	2,079	2,485	2,373
Interest Charges			
AFUDC - borrowed.	(267)	(103)	(188)
Other	7,324	6,273	7,227
Total interest charges.	7,057	6,170	7,039

Net Income (Loss) from continuing operations before preferred dividends	10,328	11,395	11,793
Net Income (Loss) from discontinued operations, including provisions for loss on disposal	79	99	(182)
Dividends on Preferred Stock	3	96	933
Net Income (Loss) Applicable to Common Stock	$ 10,404	$ 11,398	$ 10,678
Common Stock Data			
Basic earnings per share-continuing operations	$ 2.08	$ 2.02	$ 1.93
Basic earnings per share-discontinued operations	$ 0.01	$ 0.02	$ (0.03)
Basic earnings per share	$ 2.09	$ 2.04	$ 1.90
Diluted earnings (loss) per share from continuing operations	$ 2.01	$ 1.96	$ 1.88
Diluted earnings (loss) per share from discontinued operations	$ 0.01	$ 0.02	$ (0.03)
Diluted earnings (loss) per share	$ 2.02	$ 1.98	$ 1.85
Cash dividends declared per share	$ 0.60	$ 0.60	$ 0.55
Weighted average shares outstanding-basic	4,980	5,592	5,630
Weighted average share equivalents outstanding-diluted	5,140	5,756	5,789

FINANCIAL CONDITION AS OF DECEMBER 31

In thousands	2003	2002	2001	2000	1999
ASSETS					
Utility Plant, Net	$228,862	$223,476	$196,858	$194,672	$192,896
Other Investments	13,706	21,552	20,945	20,730	20,665
Current Assets	31,688	31,432	36,183	53,652	33,238
Deferred Charges	55,590	60,390	72,468	46,036	41,853
Non-Utility Assets	1,105	995	1,075	1,518	11,099
Total Assets	$330,951	$337,845	$327,529	$316,608	$299,751
CAPITALIZATION AND LIABILITIES					
Common Stock Equity	$ 99,915	$ 91,722	$101,277	$ 92,044	$100,645
Redeemable Cumulative Preferred Stock	-	55	12,560	12,795	14,435
Long-Term Debt, Less Current Maturities	93,000	93,000	74,400	72,100	81,800
Capital Lease Obligation	4,963	5,287	5,959	6,449	7,038
Current Liabilities	22,715	38,491	38,841	68,109	36,708
Deferred Credits and Other	108,868	107,349	92,791	61,794	59,125
Non-Utility Liabilities	1,490	1,941	1,701	3,317	-
Total Capitalization and Liabilities	$330,951	$337,845	$327,529	$316,608	$299,751

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

EXECUTIVE OVERVIEW - Green Mountain Power Corporation (the "Company") generates virtually all of its earnings from retail electricity sales. Our retail electricity sales grow at an average annual rate of between one and two percent, about average for most electric utility companies in New England. While wholesale revenues are significant, they have relatively minor impact on our operating results and financial condition. The Company is regulated and cannot adjust prices of retail electricity sales without regulatory approval from the Vermont Public Service Board ("VPSB").

The Company increased its dividend in February 2004 from an annual rate of $0.76 per share to $0.88 per share. The Company's dividend payout ratio remains comparatively low, at less than 45 percent of 2003 earnings. We expect to grow our dividend payout ratio to between 50 and 70 percent over the next five years, in line with other electric utilities having similar risk profiles, so long as financial and operating results permit.

Fair regulatory treatment is fundamental to maintaining the Company's financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders. In December 2003, the Company received approval from the VPSB of a new rate plan covering the period 2003 through 2006, which sets rates at levels the Company believes will provide an improved opportunity to recover our costs, and to earn our allowed rate of return.

Power supply expenses are equivalent to approximately 70 percent of total revenues. The Company's need to seek rate increases from its customers frequently moves in tandem with increases in our power supply costs. We have entered into long-term power supply contracts for most of our energy needs. All of our power supply contract costs are currently being recognized in the rates we charge our customers. The risks associated with our power supply resources, including outage, curtailment, and other delivery risks, the timing of contract expirations, the volatility of wholesale prices, and other factors impacting our power supply resources and how they relate to customer demand are discussed below under Item 7a, "Quantitative and Qualitative Disclosure about Market Risk, and Other Risk Factors."

We also discuss other risks, including load risk related to our largest customer, International Business Machines Corporation ("IBM"), and contingencies that could have a significant impact on future operating results and our financial condition.

Growth opportunities beyond the Company's normal investment in its infrastructure are also discussed, and include a planned increase in our equity investment in Vermont Electric Power Company, Inc. ("VELCO") and a planned increase in sales of utility services.

In this section, we explain the general financial condition and the results of operations for 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 affect our overall financial condition.

Our critical accounting policies are discussed below under Item 7a, "Quantitative And Qualitative Disclosures About Market Risk, And Other Factors," under "Liquidity and Capital Resources - Pension," in Note A, "Significant Accounting Policies," and in Note H, "Pension and Retirement Plans." Management believes the most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate; the manner in which we account for certain power supply arrangements that qualify as derivatives; the assumptions that we make regarding defined benefit plans; and revenue recognition, particularly as it relates to unbilled and deferred revenues. These accounting policies, among others, affect the Company's significant judgments and estimates used in the preparation of its consolidated financial statements.

There are statements in this section that contain projections or estimates 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 include:

regulatory and judicial decisions or legislation
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
industry restructuring and cost recovery (including stranded costs)
weather

We address these items in more detail below.

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

EARNINGS SUMMARY YEARS ENDED

	2003	2002	2001
Consolidated earnings per share of common stock	$ 2.02	$ 1.98	$ 1.85
Consolidated return on average common equity. .	10.76%	11.03%	11.02%

The Company reported consolidated earnings of $2.02 per share of common stock, diluted, in 2003 compared to consolidated earnings of $1.98 per share, diluted, in 2002. The improvement in earnings per share reflected reduced power supply expenses to serve retail sales, an increase in sales to residential customers and a reduction in the number of common stock shares outstanding. These favorable developments more than offset increased administrative and general costs, a reduction in the Company's allowed rate of return, increased interest expense in 2003, and a decrease in the recognition of deferred revenues, compared with 2002.

Our financial health improved during 2001 and 2002. As a result, we were able to reduce significantly our cost of capital in the fourth quarter of 2002 by issuing new long-term debt and using a portion of the proceeds to acquire approximately 812,000 shares of our common stock. Our 2003 earnings per share improved by approximately $0.09 per share as a result of the stock buyback.

In December 2003, the VPSB approved a rate plan for the period 2003 through 2006 (the "2003 Rate Plan"), jointly proposed by the Company and the Vermont

Department of Public Service (the "Department" or the "DPS"). The 2003 Rate Plan provides the Company with a stable, predictable rate path through 2006, a plan for full recovery of the Company's principal regulatory assets, and an improved opportunity for the Company to earn its allowed rate of return through 2006. The 2003 Rate Plan calls for no retail rate increases in 2003 or 2004, then scheduled increases of 1.9 percent effective January 1, 2005, and 0.9 percent effective January 1, 2006. The 2003 Rate Plan sets the Company's allowed return on equity from core utility operations at 10.5 percent, effective with 2003, and provides for an earnings cap at that level through 2006. The 2003 Rate Plan is summarized in more detail below under "Rates."

The VPSB's January 2001 rate order (the "2001 Settlement Order") allowed the Company to defer revenues of approximately $8.5 million, generated by leveling winter/summer rates during 2001, to help offset costs and realize our allowed rate of return during the 2001-2003 period. We recognized approximately $1.1 million of these deferred revenues to achieve our allowed rate of return during 2003, compared with approximately $4.4 million recognized in 2002. The VPSB has permitted the Company to carry over unused deferred revenues totaling approximately $3.0 million to 2004 as part of the 2003 Rate Plan.

The improvement in earnings from continuing operations in 2002, compared with 2001, resulted primarily from lower capital costs and other operating expenses, including:

$0.9 million reduction in interest expense, reflecting lower interest rates and average debt levels;

$0.8 million reduction in preferred stock dividends, reflecting the Company's redemption of outstanding preferred stock; and

Recognition of $4.4 million in revenue deferred from 2001 under the 2001 Settlement Order.

These favorable results were partially offset by increased maintenance expense, transmission expense and power supply expense to serve retail customers, compared to 2001.

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

We consider our principal risks to include power supply risks, our regulatory environment (particularly as it relates to the Company's periodic need for rate relief), risks associated with our principal customer, IBM, pension and postretirement healthcare costs and weather. Discussion of these and other risks, as well as factors contributing to mitigation of these risks, follows.

POWER SUPPLY RISK.

The Company's most significant power supply contracts are the Hydro-Quebec Vermont Joint Owners ("VJO") Contract (the "VJO Contract") and the Vermont Yankee Nuclear Power Corporation ("VY" or "Vermont Yankee") contract (the "Vermont Yankee Contract") which are summarized in the following table.

	2003 MWh	2003 $/MWh	2002 MWh	2002 $/MWh	Contract Expires
VJO Contract.	664,225	$69.81	724,708	$66.11	2015
Vermont Yankee Contract	884,585	$43.08	771,782	$44.55	2012

All of the Company's power supply contract costs are currently being recovered through rates approved by the VPSB.

We expect approximately 90 percent of our estimated customer demand ("load") requirements through 2006 to be met by these contracts and by our generation and other power supply resources. These contracts and resources significantly reduce the Company's exposure to volatility in wholesale energy market prices. The Company's power supply contracts are described in more detail below under the heading "Power Contract Commitments."

A primary factor affecting future operating results is the volatility of the wholesale electricity market. Implementation of New England's wholesale market for electricity has increased volatility of wholesale power prices. Periods frequently occur when weather, availability of power supply resources and other factors cause significant differences between customer demand and electricity supply. Because electricity cannot be stored, in these situations the Company must buy or sell the difference into a marketplace that has experienced volatile energy prices. Volatility and market price trends also make it more difficult to extend or enter into new power supply contracts at prices that avoid the need for rate relief.

During 2002, we estimate that the Company paid an additional $1.0 million for replacement power as the result of an unscheduled outage at the Vermont Yankee nuclear power plant. While the Vermont Yankee plant has had an excellent operating record, future unscheduled outages could occur at times when replacement energy costs are above Vermont Yankee Contract costs.

We sometimes experience energy delivery deficiencies under the VJO Contract as a result of outages or other problems with the transmission interconnection facilities over which we schedule deliveries. When such deficiencies occur, we purchase replacement energy on the wholesale market, usually at prices that are higher than VJO Contract costs.

Under the VJO 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 contract. Hydro-Quebec exercised the first of these load reduction options, effective for the year 2003. The net cost of Hydro-Quebec's exercise of this option increased power supply expense during 2003 by approximately $1.2 million. During 2003, Hydro-Quebec exercised its second option to reduce the load factor for 2004, which we estimate will increase power supply expense by approximately $1.0 million. We expect Hydro-Quebec to exercise its third option in 2004 for deliveries occurring principally during 2005, at an estimated cost of $1.0 million to $1.2 million, based on current wholesale market prices for 2005.

Hydro-Quebec also retains the right under the VJO Contract 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. Hydro-Quebec has not exercised this right and has not communicated to the Company any present intention to do so.

Under the VJO Contract, the VJO, including the Company, have two options to adjust deliveries by a five percent load factor. These options cannot be used to offset Hydro-Quebec's reductions through 2005, but may be used after 2005 to manage power supply costs.

The Company has established a risk management program designed 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. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. Some of these transactions present the risk of potential losses from adverse changes in commodity prices. Our risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions. Our principal power supply contract counter-parties and generators, Hydro-Quebec, Entergy Nuclear Vermont Yankee, LLC ("ENVY") and Morgan Stanley Capital Group, Inc. ("Morgan Stanley"), all currently have investment grade credit ratings.

The Company has a contract with Morgan Stanley (the "Morgan Stanley Contract") that is used to hedge our power supply costs against increases in fossil fuel prices. Morgan Stanley purchases the majority of the Company's power supply resources at index prices for fossil fuel resources and specified prices for contracted resources and then sells power to the Company at a fixed rate to serve pre-established load requirements. This contract, along with other power supply commitments, allows us to fix the cost of most of our power supply requirements, subject to power resource availability and other risks. The Morgan Stanley Contract is described in more detail below under the heading "Power Contract Commitments." The Morgan Stanley Contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133") and is effective through December 31, 2006. Management has estimated the fair value of the future net benefit of this arrangement at December 31, 2003, is approximately $4.0 million.

We currently have an arrangement that grants Hydro-Quebec an option (the "9701 arrangement") to call power at prices that are expected to be below estimated future market rates. The 9701 arrangement is described in more detail below under the heading "Power Supply Expenses." 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, 2003, is approximately $23.7 million. We sometimes use forward contracts to hedge forecasted calls by Hydro-Quebec under the 9701 arrangement.

The table below presents assumptions used to estimate the fair value of the Morgan Stanley Contract and the 9701 arrangement. The forward prices for electricity used in this analysis are consistent with the Company's current long-term wholesale energy price forecast.

	Option Value Model	Risk Free Interest Rate	Price Volatility	Average Forward Price	Contract Expires
Morgan Stanley Contract	Deterministic	3.4%	32%-29%	$ 42	2006
9701 Arrangement. . . .	Black-Scholes	4.6%	48%-27%	$ 60	2015

The table below presents the Company's market risk of the Morgan Stanley and Hydro-Quebec derivatives, estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in wholesale energy prices, which nets to approximately $1.2 million. Actual results may differ materially from the table illustration. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are deferred.

Commodity Price Risk	At December 31, 2003 Fair Value(Cost)	Market Risk
	(in thousands)	

Morgan Stanley Contract	$ 3,990	$ 2,160
9701 Arrangement. . . .	(23,724)	(3,342)
	(19,734)	(1,182)

REGULATORY RISK

Management believes that fair regulatory treatment is crucial to maintaining its financial stability, including its ability to attract capital.

Vermont is the only state in the New England region that has not adopted some form of electric industry restructuring. The Company, like all other electric utilities in Vermont, accordingly operates as a vertically integrated electric utility, with the obligation to serve all customers in our service territory with electrical transmission, distribution and energy supplies sufficient to satisfy customer load requirements.

Vermont does not have a fuel or purchased-power adjustment clause that would allow increases in power supply costs to be recovered immediately in the rates we charge customers. Historically, however, the VPSB has allowed electric utilities to defer material unexpected increases in power supply costs to future periods to permit recovery in future rates. Vermont law also allows electric utilities to seek temporary rate increases if deemed necessary by the VPSB to provide adequate and efficient service or to preserve the viability of the utility.

Electric utility rates in Vermont are set based on the 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 filed its last retail rate case during 1998. Since that time we have deferred a material amount of expenditures as regulatory assets. These regulatory assets have been judged as probable of recovery by management. As of December 31, 2003, the most significant regulatory assets not being recovered in current rates are the following:

Regulatory assets

	At December 31, 2003	2002
	(in thousands)	
Pine Street barge canal . .	$ 12,954	$13,019
Demand-side management. . .	6,713	6,434
Unscheduled VY outage costs	2,178	2,002
Total	$ 21,845	$21,455

The 2003 Rate Plan, approved by the VPSB in December 2003, provides for amortization and recovery of all of the regulatory assets listed above, beginning January 1, 2005. The Pine Street Barge Canal regulatory asset will be amortized over a period of 20 years without a return on the remaining balance of the asset. The remaining assets will be amortized over a five-year period. Both the demand-side management and the unscheduled VY outage costs accrue a return defined by the Federal Energy Regulatory Commission ("FERC") based on the capital structure of the utility ("AFUDC rate"). The AFUDC rate for 2003 for the Company was approximately 8.5 percent.

The Company currently complies with the provisions of SFAS 71. If we had determined that the Company no longer met the criteria for following SFAS 71, at December 31, 2003, the accounting impact would have been an extraordinary non-cash charge to operations of $55.5 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;

competition that limited our ability to sell utility services or products at rates that will recover costs; or

regulatory actions that limit rate relief to a level insufficient to recover costs.

There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont. Legislation has been introduced in the Vermont legislature that would permit (but not require) the Company to negotiate with individual customers to permit such customers to procure their own electric power supply requirements, subject to VPSB approval. We cannot predict whether this legislation will be enacted. If enacted, the Company would not negotiate any such arrangement unless, in our estimation, the arrangement assured the Company of full recovery of any resulting stranded costs and that the Company's financial condition would not otherwise be adversely affected.

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 wholesale market price of power. We have discussed various market price scenarios with interested parties for the purpose of identifying stranded costs. Based on preliminary market price assumptions, which are likely to change, we estimate the Company's stranded costs to be between $206 million and $252 million over the life of the Company's current contracts.

If Vermont adopted retail competition or some other form of electric industry restructuring or if the VPSB issued a regulatory order containing provisions that did not allow the Company to recover above-market power costs, the Company could be required 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.

CUSTOMER CONCENTRATION RISK - IBM, the Company's largest customer, operates a manufacturing facility in Essex Junction, Vermont. IBM's electricity requirements for its facility accounted for approximately 24.1, 25.7, and 26.6 percent of the Company's retail MWh sales in 2003, 2002, and 2001, respectively, and 16.6, 17.3, and 19.2 percent of the Company's retail operating revenues in 2003, 2002, and 2001, 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 22, 2003, the VPSB approved a new three-year agreement between the Company and IBM, ending December 31, 2006. The price of power under the agreement is above our marginal costs of providing incremental service to IBM. The VPSB approval provides that the agreement automatically terminates if IBM's full-time-equivalent employment level at its Vermont facility served by the agreement drops by more than 5 percent from the level on the date of VPSB approval.

IBM has reduced its Vermont workforce by approximately 2,500 since 2001, to a level of approximately 6,000 employees. Company revenue from sales of electricity to IBM declined $1.8 million in 2003 compared with 2002. Our operating results were not adversely impacted by the reduction in sales to IBM due to continued revenue growth in other customer classes and because the gross margin on sales to IBM is relatively low. If we experienced a material reduction in earnings as a result of significantly lower retail sales, we would seek a retail rate increase from the VPSB. The Company is permitted to seek such a rate increase request under our approved 2003 Rate Plan. We are 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, that a hypothetical shutdown of the IBM facility would require a retail rate increase for all our remaining customers in the range of five to eight percent.

PENSION AND POSTRETIREMENT HEALTH CARE RISK - Other critical accounting policies involve the Company's defined benefit pension and postretirement health care benefit plans. The reported costs of these plans depend upon numerous factors relating to actual plan experience and assumptions of future experience.

Pension and postretirement health care costs are affected by actual employee demographics, Company contributions to the plans, earnings on plan assets, and, for our postretirement health care plan, health care cost trends. The Company contributed $1.0 million and $3.5 million to its pension plan during 2002 and 2003, respectively, and we expect to contribute between $2.0 and $3.0 million during 2004.

Our 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 increase or decrease 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.

On December 17, 2003, the Company's employees ratified a four-year labor agreement that provides annual wage increases of between 3.5 and 4 percent and improved 401(k) and pension benefits for employees. The new labor agreement caps future postretirement healthcare employee benefits provided by the Company for the majority of the present workforce. The cap on postretirement healthcare benefits is set approximately 13 percent above 2003 costs and grows at a 3 percent annual rate. This cap should reduce the rate at which postretirement healthcare expenses grow in the future.

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. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income ("OCI"). Favorable pension plan investment returns during 2003 reduced the OCI charge and related net liability by $587,000. The 2002 OCI charge and the 2003 OCI benefit had no effect on net income for either year.

WEATHER - The Company now uses weather insurance to mitigate some of the risk of lost electricity sales caused by unfavorable weather conditions. The Company has purchased weather insurance coverage for 2004. Coverage is based on cumulative variations from normal weather, measured in net heating and cooling degree-days.

RESULTS OF OPERATIONS

OPERATING REVENUES AND MWH SALES - Operating revenues, megawatthour ("MWh") sales and number of customers for the years ended 2003, 2002 and 2001 were as follows:

	Years ended December 31, 2003	2002	2001
	(dollars in thousands)		
Operating Revenues			
Retail*.	$ 198,717	$ 201,052	$ 195,093
Sales for Resale . .	78,901	70,646	83,804
Other.	2,852	2,910	4,567
Total Operating Revenues	$ 280,470	$ 274,608	$ 283,464
MWH Sales-Retail	1,934,340	1,948,190	1,953,154
MWH Sales for Resale . .	2,287,039	2,107,941	2,368,887
Total MWH Sales.	4,221,379	4,056,131	4,322,041

*Retail revenues include $1.1 million, $4.4 million and $0.0 million of deferred revenue recognized for 2003, 2002, and 2001, respectively.

Average Number of Customers

	Years ended December 31, 2003	2002	2001
Residential	74,693	73,861	73,249
Commercial and Industrial	13,369	13,194	13,006
Other	65	65	65
Total Number of Customers. .	88,127	87,120	86,320

Comparative changes in operating revenues are summarized below:

Change in Operating Revenues	2002 to 2003	2001 to 2002
	(In thousands)	
Retail Rates	$ (912)	$ 6,471
Retail Sales Volume.	(1,423)	(512)
Resales and Other Revenues .	8,197	(14,815)
Change in Operating Revenues	$ 5,862	$ (8,856)

In 2003, total electricity sales increased 4.1 percent compared with 2002, due to increased wholesale sales and sales to residential and commercial customers, partially offset by decreased sales to industrial customers. Total operating revenues increased $5.9 million, or 2.1 percent, compared with 2002 as a result of the following:

Increased wholesale revenues of $8.3 million, primarily due to increased system sales during peak demand periods and increased sales to Hydro-Quebec under the 9701 arrangement;

Increased retail residential revenues of $3.2 million, or 4.5 percent, arising from increased sales of electricity; and

Increased retail small commercial and industrial ("C&I") revenues of $900,000, or 1.3 percent, arising from increased sales of electricity.

These increases were partially offset for the following reasons:

The Company recognized $1.1 million in deferred revenues under the 2001 Settlement Order, reduced from $4.4 million recognized in 2002.

Decreased retail large C&I revenues of $2.6 million, or 1.7 percent, when compared with 2002, resulting from a decline in sales of electricity to this customer class.

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 Morgan Stanley 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 2001 Settlement Order. Increased sales to residential and commercial customers also contributed to higher retail revenues, partially offset by a decline in revenues from IBM.

POWER SUPPLY EXPENSES - Power supply expenses constituted 74.4, 74.5 and 75.3 percent of total operating expenses for the years 2003, 2002, and 2001, respectively.

Power supply expenses increased by $3.9 million, or 2.0 percent, in 2003 when compared with 2002, and resulted from the following:

an $8.3 million increase in the cost of power purchased for resale;

a $2.7 million increase in power supply expenses under agreements with Hydro-Quebec;

higher costs of electricity supplied by independent power producers; and

higher wholesale prices for electricity.

These increases were partially offset by an $8.9 million decrease in the cost of power under our contract with Morgan Stanley and lower unit prices from Vermont Yankee.

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 Morgan Stanley 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:
a $6.2 million increase in the cost of power purchased from Morgan Stanley;
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 CONTRACT COMMITMENTS - On February 11, 1999, the Company entered into a contract with Morgan Stanley (the "Morgan Stanley Contract") designed to manage price risks associated with changing fossil fuel prices. In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006.

Under the Morgan Stanley Contract, on a daily basis, and at Morgan Stanley's discretion, we sell power to Morgan Stanley 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. Morgan Stanley sells to the Company, at a predefined price, power sufficient to serve pre-established load requirements. Morgan Stanley is also responsible for scheduling supply resources. We remain responsible for resource performance and availability. Morgan Stanley provides no coverage against major unscheduled power supply outages. Beginning January 1, 2004, the Company will reduce the power that it sells to Morgan Stanley. Some of our power-supply resources, including purchases pursuant to our Hydro-Quebec and Vermont Yankee contracts, which were sold to Morgan Stanley through 2003, will no longer be included in the Morgan Stanley Contract. This reduction in sales to Morgan Stanley is expected to reduce wholesale revenues by approximately $64 million and correspondingly to reduce power supply expense by a similar amount. We do not expect this change to adversely affect the Company's opportunity to earn its allowed rate of return during 2004.

The Company's current purchases under the VJO Contract with Hydro-Quebec 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, beginning in November 1995.

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 also parties to the contract would be required to purchase their proportionate share of the power supply entitlement of any defaulting utility. The Company is not aware of any instance where this provision has been invoked by Hydro-Quebec.

Under the Company's 9701 arrangement, 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 VJO Contract, which ends in 2015, Hydro-Quebec may purchase up to 52,500 MWh on an annual basis ("option A") at the VJO Contract energy price, which is substantially below current market prices. The cumulative amount of energy that may be purchased under option A may not exceed 950,000 MWh (52,500 MWh in each contract year.)

Over the same period, Hydro-Quebec may exercise an option to purchase up to 200,000 MWh on an annual basis at the VJO Contract energy price ("option B"). The cumulative amount of energy that may be purchased under option B may not exceed 600,000 MWh. As of December 31, 2003, Hydro-Quebec had purchased 513,000 MWh under option B. The Company expects Hydro-Quebec to call its remaining entitlements under option B during 2004 and 2005.

In 2003, Hydro-Quebec exercised option A and option B, and called for delivery to third parties at a net expense to the Company of approximately $4.5 million, including capacity charges.

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.

We believe that it is probable that Hydro-Quebec will call options A and B for 2004, and the Company has purchased replacement power at a net cost of $3.2 million. The Company has also covered 54 percent of expected calls during 2005 at a net cost of $1.1 million.

VERMONT YANKEE NUCLEAR POWER CORPORATION

On July 31, 2002, Vermont Yankee completed the sale of its nuclear power plant to ENVY. As part of the sale transaction, Vermont Yankee entered into a Power Purchase Agreement ("PPA") with ENVY pursuant to which ENVY is obligated to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of our energy requirements. Prices under the PPA range from $39 to $45 per MWh for the period beginning January 2003, substantially lower than our forecasted cost if Vermont Yankee had continued to own and operate the plant facilities. In 2002, contract prices ranged from $49 to $55 under the PPA, higher than the forecasted cost of continued ownership. The PPA contains a provision known as the "low market adjuster," which calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning in November 2005. If market prices rise, however, PPA 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 ENVY plant.

The Company received $8.2 million in October 2003, representing its share of the Vermont Yankee power plant sale proceeds, and used the proceeds to retire debt.

The Vermont Yankee sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervenor parties to the VPSB approval proceeding appealed the VPSB approval to the Vermont Supreme Court. The Court rejected the appeal and affirmed the VPSB approval during 2003.

OTHER OPERATING EXPENSES - Other operating expenses increased $3.5 million, or 24.5 percent, in 2003 compared with 2002 primarily due to increased employee benefit expenses and expenses related to corporate governance. A cap on post-retirement healthcare benefits, improved market returns and benefit plan funding should reduce growth in administrative and general expenses in 2004.

Other operating expenses decreased $1.7 million, or 10.9 percent, in 2002 compared with 2001. The decrease was primarily due to reduced consulting expenses of approximately $1.0 million and reduced distribution expenses of $0.6 million.

TRANSMISSION EXPENSES - Transmission expenses decreased $438,000, or 2.9 percent, in 2003 compared with 2002, due to decreased congestion costs allocated by ISO New England to Vermont utilities in conjunction with transition to a new standard market design ("SMD"). See discussion below.

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

The Independent System Operator of New England ("ISO-NE" or "ISO New England") was created to manage the operations of the New England Power Pool ("NEPOOL"), effective May 1, 1999. ISO-NE operates a market for all New England states 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.

During 2002, the FERC accepted ISO-NE's request to implement a SMD governing wholesale energy sales in New England. ISO-NE 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. ISO-NE and NEPOOL have committed to facilitation of a stakeholder process to examine alternative pricing options, including alternatives to nodal pricing, and to file their report with FERC in July 2004. We believe that nodal pricing could result in a material adverse impact on our power supply and/or transmission costs, if adopted.

On October 31, 2003, ISO-NE, together with New England's principal transmission system owners including VELCO, filed a request for approval of a regional transmission organization for New England ("RTO-NE"). The proposed RTO-NE would become the provider of regional transmission service in New England, with operational control of the bulk power system and responsibility for administering markets currently operated and administered by ISO-NE. If the RTO is approved by FERC, the current ISO-NE agreement with the New England Power Pool ("NEPOOL"), the Restated NEPOOL Agreement, the NEPOOL Open Access Transmission Tariff and individual local tariffs currently maintained by New England transmission owners would terminate and be superseded by new RTO-NE agreements. Also on October 31, 2003, certain transmission owners in New England, including the Company, reached an agreement to submit a tariff, agreements and other documents to FERC to include costs associated with certain transmission facilities, known as the Highgate Facilities, of which the Company is a part owner, in region-wide rates as set forth in the RTO-NE proposal. The Company cannot predict whether or when FERC will approve the RTO-NE proposal, or what modifications may be made to the proposal while pending before FERC.

VELCO, the owner and operator of Vermont's principal electric transmission system assets, 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. We own approximately 29 percent of VELCO. The proposed Northwest Reliability Project must be approved by the VPSB. Several Vermont municipalities, citizen groups and individuals have intervened in the VPSB proceedings to oppose or request modifications to the project. If approved, the project is estimated to cost approximately $130 million through 2007. VELCO intends to finance the costs of constructing the Northwest Reliability Project in part through increased equity investment. The Company plans to invest approximately $20 million in VELCO to support this and other transmission projects through 2007. Under current NEPOOL and ISO-NE rules, which require qualifying large transmission project costs to be shared among all New England utilities, most of the costs of the Northwest Reliability Project will be allocated throughout the New England region, with Vermont utilities responsible for approximately five percent of allocated costs.

In August 2003, a coalition of New England public utility commissions and other parties challenged the NEPOOL and ISO-NE transmission cost allocation rules. On December 18, 2003, FERC rejected this challenge. FERC's order is subject to pending requests for rehearing and has been appealed to the US Court of Appeals for the D.C. Circuit. If the current transmission cost allocation rules are modified or eliminated, Vermont utilities, including the Company, could be required to bear a greater proportion, and potentially all, of the cost of the Northwest Reliability Project.

MAINTENANCE EXPENSES - Maintenance expenses increased $211,000, or 2.4 percent, in 2003 compared with 2002, due to increased expenditures related to hydroelectric generation and transmission facilities.

Maintenance expenses increased $1.7 million, or 24.6 percent, in 2002 compared with 2001 due to increased expenditures related to storm damage and right-of-way maintenance programs.

DEPRECIATION AND AMORTIZATION - Depreciation and amortization expense decreased $348,000, or 2.5 percent, in 2003 compared with 2002 due to reductions in amortization of conservation and software programs, partially offset by increased depreciation of utility plant in service.

Depreciation and amortization expense decreased $143,000, 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.

TAXES OTHER THAN INCOME - Taxes other than income taxes decreased $201,000, or 2.6 percent, in 2003 compared with 2002 due to reductions in property taxes.

Taxes other than income taxes increased $87,000, or 1.2 percent, in 2002 compared with 2001 due to an increase in property taxes.

INCOME TAXES - Income tax expense decreased $923,000, or 15.2 percent, in 2003 compared with 2002 due to a decrease in the Company's taxable income, an increase in non-taxable income and the use of tax credits. Income tax expense decreased $905,000 in 2002 compared with 2001 due to a decrease in the Company's taxable income.

OTHER INCOME - Other income decreased $406,000, or 16.4 percent, in 2003 compared with 2002 due primarily to reduced earnings on investment in Vermont Yankee as a result of the sale of the Vermont Yankee plant in 2002.

Other income increased $112,000, or 4.7 percent, in 2002 compared with 2001 due primarily to Vermont Yankee recognition of deferred tax assets arising in conjunction with the sale of the Vermont Yankee plant, offset in part by payments made to Vermont Yankee owners located outside of Vermont necessary to close the sale of the Vermont Yankee plant.

INTEREST EXPENSE - Interest expense increased $887,000, or 14.4 percent, in 2003 compared with 2002 primarily due to a $42 million long-term debt issuance in December 2002.

Interest expense decreased $869,000, 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.

DIVIDENDS ON PREFERRED STOCK - Dividends on preferred stock decreased $93,000, or 96.9 percent, in 2003 compared with 2002, due to the repurchase of all outstanding preferred stock during 2003. Dividends on preferred stock decreased $837,000, 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.

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.

PINE STREET BARGE CANAL SUPERFUND SITE - In 1999, the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal Superfund site in Burlington, Vermont, known as the "Pine Street Barge Canal." The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. In 2003, the Company expended $2.6 million to cover its obligations under the consent decree and we have estimated total future costs of the Company's future obligations under the consent decree to be $8.5 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have recorded a regulatory asset of $13.0 million to reflect unrecovered past and future Pine Street costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company will begin to amortize past unrecovered costs in 2005. The Company will amortize the full amount of incurred costs over 20 years without a return. The amortization will be allowed in future rates, without disallowance or adjustment, until fully amortized.

RATES

RETAIL RATE CASES - On December 22, 2003, the VPSB approved our 2003 Rate Plan, jointly proposed earlier in the year by the Company and the Vermont Department of Public Service. The 2003 Rate Plan covers the period from 2003 through 2006 and includes the following principal elements:

The Company's rates will remain unchanged through 2004. The 2003 Rate Plan allows the Company to raise rates 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. If the Company's cost of service filings in 2005 or 2006 establish that a lesser rate increase is required for the Company to meet its revenue requirements, the Company will implement the lesser rate increase.

The Company may seek additional rate increases in extraordinary circumstances, such as severe storm repair costs, natural disasters, extended unanticipated unit outages, or significant losses of customer load.

The Company's allowed return on equity is reduced from 11.25 percent to 10.5 percent, for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on core utility operations are capped at 10.5 percent. Any excess earnings in 2004 will be applied to reduce regulatory assets. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.

The Company will carry forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003, from the Company's 2001 Settlement Order (summarized below). These revenues will be applied in 2004 to offset increased costs or, if applicable, reduce regulatory assets as determined by the DPS.

The Company will amortize (recover) certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, beginning in January 2005, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

The Company will file with the VPSB in early 2004 a new fully-allocated cost of service study and rate re-design, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design will be subject to VPSB approval and is not expected to adversely affect operating results.

The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted in Vermont in 2003. If the Company and Department agree on such a plan, and it is approved by the VPSB, the alternative regulation plan would supersede the 2003 Rate Plan.

In January 2001, the VPSB issued the 2001 Settlement Order, which included the following:

The Company received a rate increase of 3.42 percent above existing rates and prior temporary rate increases became permanent;

Rates were set at levels that recover the Company's VJO Contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;

Seasonal rates were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001, which was deferred and available to be used to offset increased costs during 2002 and 2003; and

The Company agreed to an earnings cap on core utility operations of 11.25 percent return on equity, with amounts earned over the limit being used to write off regulatory assets.

The 2001 Settlement Order also imposed 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 until new rates go into effect, which will occur in January 2005.

LIQUIDITY AND CAPITAL RESOURCES

CONSTRUCTION AND INVESTMENTS - Our capital requirements result from the need to construct facilities or to invest in programs to meet anticipated customer demand for electric service. The Company plans to invest up to $20 million in VELCO through 2007, subject to regulatory approval of the Northwest Reliability Project. See detailed discussion under "Transmission Expenses."

The Company offers utility services, primarily line construction and electrical services, principally to municipal and business customers. Sales of these services have grown from approximately $700,000 in 2001 to approximately $2.5 million in 2003. Sales of these services have allowed the Company to serve its customers more efficiently and have improved cash flow.

Future capital expenditures are expected to approximate $20 million annually. Expected reductions in Pine Street remediation costs should be offset by increased generation expenditures. Capital expenditures, net of customer advances for construction, over the past three years and forecasted for 2004 are as follows:

	Generation	Transmission	Distribution	Other*	Total
			(In thousands)		
Actual:					
2001	$ 2,323	$ 1,219	$ 8,567	$ 3,529	$15,638
2002	3,258	1,827	9,173	7,267	$21,525
2003	2,629	1,496	7,760	$ 7,064	$18,949
Forecast:					
2004	$ 4,122	$ 4,280	$ 6,036	$ 7,162	$21,600

* Other includes Pine Street Barge Canal expenditures of $1.5 million in 2001, $1.8 million in 2002, $2.5 million in 2003 and an estimated $1.1 million in 2004.

DIVIDEND POLICY - The annual dividend was $0.60 per share for the year ended December 31, 2002. The annual dividend rate was increased by the Company's Board of Directors from $0.55 per share to $0.76 per share beginning with the $0.19 quarterly dividend declared in December 2002. On February 9, 2004, the annual dividend rate was increased from $0.76 per share to $0.88 per share, a payout ratio of approximately 44 percent based on 2003 earnings. The Company expects to increase the dividend in the first quarter of each year until the payout ratio falls between 50 percent and 70 percent of anticipated earnings. We believe this payout ratio to be consistent with that of other electric utilities having similar risk profiles.

FINANCING AND CAPITALIZATION

At December 31, 2003, our capitalization consisted of approximately 51 percent common equity and 49 percent debt, inclusive of the Company's capital lease obligations.

During June 2003, the Company negotiated a 364-day revolving credit agreement (the "Fleet-Sovereign Agreement") with Fleet Financial Services ("Fleet") joined by Sovereign Bank. The Fleet-Sovereign Agreement is for $20.0 million, unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was $500,000 outstanding with a weighted average rate of 4.0 percent on the Fleet-Sovereign Agreement at December 31, 2003. There was no non-utility short-term debt outstanding at December 31, 2003 or 2002. The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2004.

During 2002, we redeemed $5.1 million of 10.0 percent first mortgage bonds and $12.5 million of outstanding preferred stock. We also completed a "Dutch Auction" self-tender offer and repurchased 811,783 shares, or approximately 14 percent, of the Company's common stock outstanding for approximately $16.3 million in November 2002.

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.

The credit ratings of the Company's first mortgage bonds at December 31, 2003 were:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BBB+	Baa1	BBB

During August 2003, our rating agencies reviewed the Company's financial position and concluded the following:

Moody's affirmed the Company' senior secured debt rating at Baa1, with a stable outlook;

Fitch Ratings affirmed the ratings of the Company's first mortgage bonds at BBB+ with a stable outlook; and

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 Morgan Stanley 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, 2003.

		Payments Due by Period			
	TOTAL	2004	2005 and 2006	2007 and 2008	After 2008
	(In thousands)				
Long-term debt.	$ 93,000	$ -	$ 14,000	$ -	$ 79,000
Interest on long-term debt.	76,055	6,534	13,068	11,068	45,385
Capital lease obligations	4,963	519	958	774	2,712
Hydro-Quebec power supply contracts	623,463	49,419	101,239	101,847	370,958
Morgan Stanley Contract	38,664	13,602	25,062	-	-
Stony Brook contract.	46,081	3,509	5,754	6,328	30,490
Vermont Yankee PPA.	288,410	35,808	67,672	67,767	117,163
Total	$ 1,170,636	$109,391	$227,753	$187,784	$645,708

OFF-BALANCE SHEET ARRANGEMENTS - The Company does not use off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets through special purpose entities. We 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, including its debt service costs.

OTHER RISKS - In March 2002, voters in the Town of Rockingham, Vermont ("Rockingham") approved an article authorizing Rockingham to create a municipal utility and to acquire the electric distribution systems of the Company and/or Central Vermont Public Service Corporation located within the town. In November 2003, Rockingham notified the Company that the town intended to initiate proceedings before the town selectboard to condemn the Company's distribution and associated property located within the town. The Company sought and obtained in December 2003 a preliminary injunction from the State Superior Court prohibiting the town from proceeding with condemnation before the selectboard. The Company successfully argued that Vermont law required Rockingham to pursue any such municipalization effort by petition to the VPSB, which is required to determine both the fair value of any assets subject to municipalization and the amount of damages to the utility caused by severance of the property subject to municipalization. The preliminary injunction remains in effect and Rockingham has not filed any petition with the VPSB seeking to municipalize assets. 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 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 hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, alleging 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 in connection with this proceeding.

GOVERNANCE - During 2003, the Securities and Exchange Commission ("SEC") issued a number of rules amending disclosure requirements for public company annual reports. In order to comply with such rules, the Company makes the following disclosures:

The Company's Board of Directors has determined that David Coates, who serves on the Company's Audit Committee, qualifies as an independent financial expert under SEC rules.

The Company has adopted a Code of Ethics and Conduct that applies to all Company directors and employees, including the Company's principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. The Company's code of ethics is maintained on its website at "www.greenmountainpower.biz", Who We Are, Investors, Corporate Governance. Upon request, the Company will provide a copy of its code of ethics to any person without charge. Please send your inquiries to attention of investor relations for the Company, 163 Acorn Lane, Colchester, Vermont 05446.

Management believes the Company to be in compliance with all governance and disclosure requirements of the New York Stock Exchange, the SEC, and applicable federal and state laws, including the "Sarbanes-Oxley" Act.

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 does 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

GREEN MOUNTAIN POWER CORPORATION
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

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

GREEN MOUNTAIN POWER CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share data)

Retail revenues
Wholesale revenues

TOTAL OPERATING REVENUES
Operating expenses-Power Supply:
Purchases from others
Company-owned generation
Other operating
Transmission
Maintenance
Depreciation and amortization
Taxes other than income
Income taxes

Total operating expenses

OPERATING INCOME

OTHER INCOME
Equity in earnings of affiliates and non-utility operations
Allowance for equity funds used during construction

Other income (deductions), net

Total other income

INTEREST CHARGES
Long-term debt
Other
Allowance for borrowed funds used during construction

Total interest charges

INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS
Dividends on preferred stock

INCOME FROM CONTINUING OPERATIONS

Income (Loss) from discontinued operations, net

NET INCOME APPLICABLE TO COMMON STOCK

EARNINGS PER SHARE
Basic earnings per share from continuing operations
Basic earnings per share from discontinued operations

Basic earnings per share

Diluted earnings per share from continuing operations
Diluted earnings per share from discontinued operations

Diluted earnings per share

Weighted average shares outstanding-basic
Weighted average equivalent shares outstanding-diluted
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net income
Minimum pension liability adjustment, net of applicable income taxes of $400,000 expense and $1.6 million benefit, respectively

Other comprehensive income

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31

	2003
OPERATING ACTIVITIES:	
Income from continuing operations before preferred dividends	$ 10,32
Adjustments to reconcile net income to net cash provided by operating activities:	
Depreciation and amortization	13,80
Dividends from associated companies less equity income	88
Allowance for funds used during construction	(65
Amortization of deferred purchased power costs	31
Deferred income taxes	1,47
Benefit plan contributions	(3,50
Deferred purchased power costs	(57
Accrued purchase power contract option call	
Arbitration costs recovered (deferred)	
Rate levelization liability	(1,12
Environmental and conservation deferrals, net	(1,89
Changes in:	
Accounts receivable and accrued utility revenues	(18
Prepayments, fuel and other current assets	(1,18
Accounts payable and other current liabilities	(67
Accrued income taxes payable and receivable	(3,95
Deferred tax liability	5,77
Other	2,14
Net cash provided by continuing operations	20,99
Net change in discontinued segment	7
Net cash provided by operating activities	21,07

INVESTING ACTIVITIES:	
Construction expenditures.	(16,61
Investment in associated companies	(10
Return of Capital from associated companies.	7,61
Investment in nonutility property.	(19
Net cash used in investing activities.	(9,30
FINANCING ACTIVITIES:	
Proceeds from issuance of long term debt	
Payments to acquire treasury stock	(
(Reduction in) Proceeds from term loan	
Repurchase of preferred stock.	(8
Issuance of common stock	99
Proceeds (purchases) of certificate of deposit	
Power supply option obligation	
Reduction in long-term debt.	(8,00
Short-term debt, net	(2,00
Cash dividends	(3,79
Net cash used in financing activities.	(12,88
Net increase (decrease) in cash and cash equivalents	(1,12
Cash and cash equivalents at beginning of period	1,90
Cash and cash equivalents at end of period	78
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:	
Cash paid year-to-date for:	
Interest (net of amounts capitalized).	7,12
Income taxes	2,91
SUPPLEMENTAL DISCLOSURE OF NON-CASH INFORMATION:	
Minimum pension liability adjustment, net.	(58

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	DECEMBER 31	
	2003	2002
	(in thousands)	
ASSETS		
UTILITY PLANT		
Utility plant, at original cost	$ 324,900	$311,543
Less accumulated depreciation	110,111	102,250
Net utility plant	214,789	209,293
Property under capital lease	5,047	5,287
Construction work in progress	9,026	8,896
Total utility plant, net	228,862	223,476

OTHER INVESTMENTS			
	Associated companies, at equity	5,896	14,101
	Other investments	7,810	7,451
	Total other investments	13,706	21,552
CURRENT ASSETS			
	Cash and cash equivalents	786	1,909
	Accounts receivable, less allowance for doubtful accounts of $690 and $547	17,331	17,253
	Accrued utility revenues	6,729	6,618
	Fuel, materials and supplies, at average cost	4,498	3,349
	Prepayments	1,922	1,901
	Other	422	402
	Total current assets	31,688	31,432
DEFERRED CHARGES			
	Demand side management programs	6,713	6,434
	Purchased power costs	2,574	2,323
	Pine Street Barge Canal	12,954	13,019
	Net power supply deferral	19,734	18,405
	Power supply derivative asset	3,990	8,796
	Other deferred charges	9,625	11,413
	Total deferred charges	55,590	60,390
NON-UTILITY			
	Other current assets	217	8
	Property and equipment	248	249
	Other assets	640	738
	Total non-utility assets	1,105	995
TOTAL ASSETS		$ 330,951	$337,845

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	DECEMBER 31	
	2003	2002
(in thousands except share data)		
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,860,854 and 5,782,496)	$ 19,536	$ 19,276
Additional paid-in capital	76,081	75,347
Retained earnings.	22,786	16,171
Accumulated other comprehensive income	(1,787)	(2,374)

Treasury stock, at cost (827,639 and 827,639 shares)	(16,701)	(16,698)
Total common stock equity.	99,915	91,722
Redeemable cumulative preferred stock.	-	55
Long-term debt, less current maturities.	93,000	93,000
Total capitalization	192,915	184,777
CAPITAL LEASE OBLIGATION	4,963	5,287
CURRENT LIABILITIES		
Current maturities of preferred stock.	-	30
Current maturities of long-term debt	-	8,000
Short-term debt.	500	2,500
Accounts payable, trade and accrued liabilities. . .	8,493	7,431
Accounts payable to associated companies	6,821	8,940
Rate levelization liability.	2,970	4,091
Accrued income taxes	633	4,583
Customer deposits.	968	898
Interest accrued	1,152	1,081
Other.	1,178	937
Total current liabilities.	22,715	38,491
DEFERRED CREDITS		
Power supply derivative liability.	23,724	27,201
Accumulated deferred income taxes.	34,009	26,471
Unamortized investment tax credits	2,848	3,130
Pine Street Barge Canal cleanup liability.	7,356	8,833
Accumulated cost of removal.	21,238	19,947
Other deferred liabilities	19,693	21,767
Total deferred credits	108,868	107,349
COMMITMENTS AND CONTINGENCIES		
NON-UTILITY		
Net liabilities of discontinued segment.	1,490	1,941
Total non-utility liabilities.	1,490	1,941
TOTAL CAPITALIZATION AND LIABILITIES	$330,951	$337,845

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION
GREEN MOUNTAIN POWER CORPORATION At December 31,

	SHARES ISSUED AND OUTSTANDING				
	AUTHORIZED	2003	2002	2003	2002
				(In thousands)	

COMMON STOCK					
Common Stock, $3.33 1/3 par value	10,000,000	5,033,215	4,954,857	$ 19,536	$19,276

	AUTHORIZED	ISSUED	OUTSTANDING 2003	OUTSTANDING 2002	2003	2002
	Shares				(In thousands)	
REDEEMABLE CUMULATIVE PREFERRED STOCK,						
100 PAR VALUE						
4.75%, Class B, redeemable at						
101 per share.	15,000	15,000	-	850	$ -	$ 85
7%, Class C	15,000	15,000	-	-	-	-
9.375%, Class D, Series 1,.	40,000	40,000	-	-	-	-
7.32%, Class E, Series 1.	200,000	120,000	-	-	-	-
TOTAL PREFERRED STOCK					$ -	$ 85

	2003	2002
	(In thousands)	
LONG-TERM DEBT		
FIRST MORTGAGE BONDS		
6.41% Series due 2003.	-	8,000
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	42,000
Total Long-term Debt Outstanding	93,000	101,000
Less Current Maturities (due within one year).	-	8,000
TOTAL LONG-TERM DEBT, LESS CURRENT MATURITIES.	$ 93,000	$ 93,000

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

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	COMMON STOCK	PAID-IN	RETAINED	ACCUM COMPREH

	SHARES	AMOUNT	CAPITAL	EARNINGS	OTHER
				(Dollars in thousands)	
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.	12,691	44	42	-	
Net Income before dividends. . .	-	-	-	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.	52,804	177	342	-	
Net Income before dividends. . .	-	-	-	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	$
Common Stock Issuance:					
Compensation Programs.	78,358	260	734		
Common stock repurchase					
Net Income before dividends. . .	-	-	-	10,407	
Other Comprehensive Income(Loss)	-	-	-	-	
Common Stock Dividends	-	-	-	(3,789)	
Preferred Stock Dividends: . . .	-	-	-	(3)	
BALANCE, DECEMBER 31, 2003 . . .	5,033,215	$19,536	$ 76,081	$ 22,786	$

The accompanying notes are an integral part of the 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 89,000 customer accounts. The Company's subsidiary, Green Mountain Power Investment Company ("GMPIC"), was created in December 2002 to hold the Company's investment in Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VY").

The Company's remaining active wholly-owned subsidiary, which is not regulated by the Vermont Public Service Board ("VPSB" or the "Board"), is GMP Real Estate Corporation. The results of GMP Real Estate Corporation and the Company's unregulated rental water heater program are included in earnings of affiliates and non-utility operations in the Other Income (Deductions) section of the Consolidated Statements of Income. Summarized financial information for these wholly-owned subsidiaries, and the Company's unregulated water heater program, which earned approximately $386,000 in 2003 is as follows:

	Years ended December 31,		
	2003	2002	2001
	In thousands		
Revenue. .	$ 1,087	$ 997	$1,012
Expense. .	704	744	$ 749
Net Income	$ 383	$ 253	$ 263

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

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

The accompanying consolidated financial statements conform to accounting principles generally accepted in the United States of America 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 as summarized in the following table:

SFAS 71 DEFERRED CHARGES

	At December 31,	
	2003	2002
	(in thousands)	
Regulatory commission costs .	$ 2,181	$ 1,774
Restructuring costs	943	2,216
Preliminary survey.	1,423	1,202
Storm damages	1,129	1,905
Tree trimming	799	905

Other	3,150	3,411
Other deferred charges. . . .	9,625	11,413
Power supply.	2,574	2,323
Net power supply deferral . .	19,734	18,405
Pine Street barge canal . . .	12,954	13,019
Power supply derivative asset	3,990	8,796
Demand-side management. . . .	6,713	6,434
Total Deferred Charges. . . .	$ 55,590	$60,390

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 $9.6 million and $11.4 million at December 31, 2003 and 2002, 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.

In addition, the Company has regulatory liabilities of $25.1 million and $24.0 million at December 31, 2003 and 2002, respectively, consisting of accumulated removal costs, deferred revenue and insurance proceeds relating to VY.

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 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, 2003, based upon management's analysis of 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 capitalizing 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 are charged to accumulated depreciation. The following table summarizes the Company's investments in utility plant.

Property Summary at December 31,

	2003	2002
	In thousands	
Property Plant and Equipment:		
Intangible.	$ 14,091	$ 12,580
Generation.	68,532	66,913
Transmission.	37,093	36,846
Distribution.	178,292	170,655
General, including transportation	26,892	24,549
Total Plant in Service.	324,900	311,543
Accumulated Depreciation and Amortization	(110,111)	(102,250)
Net Plant in Service.	214,789	209,293
Capital Lease	5,047	5,287
Construction Work in Progress	9,026	8,896
Total Net Utility Plant	$ 228,862	$ 223,476

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. Other accumulated removal costs related to utility plant, estimated at approximately $21.2 million and $19.9 million for 2003 and 2002, respectively, are included in Deferred Credits.

The annual depreciation provision was approximately 3.3 percent during 2003, 3.2 percent during 2002, and 3.5 percent of total depreciable property during 2001.

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 retail sales of electricity 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. Wholesale revenues represent sales of electricity to other utilities, typically for resale, and to the Independent System Operator of New England ("ISO New England") for amounts by which our power supply resources exceed customer loads. The Company also recognizes deferred revenues, when required to achieve its allowed rate of return, under a VPSB order issued in 2001, and extended through 2004 under a subsequent VPSB order. The Company recognized $1.1 million and $4.4 million in deferred revenues during 2003 and 2002, respectively. No deferred revenues were recognized in 2001. See Note I(4) for additional information.

8. 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 2003, 2002 and 2001, the Company granted additional options of 4,000, 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 Company adopted the prospective method of accounting for stock-based compensation under SFAS 148 beginning January 1, 2003. The information presented below has been determined as if the Company accounted for all past employee and director stock options under the fair value method of that statement.

Pro-forma net income	For the years ended December 31, 2003	2002	2001
In thousands, except per share amounts			
Net income reported.	$10,404	$11,398	$10,678
Pro-forma net income	$10,242	$11,114	$10,376
Net income per share			
As reported-basic.	$ 2.09	$ 2.04	$ 1.90
Pro-forma basic.	$ 2.06	$ 1.99	$ 1.84
As reported-diluted.	$ 2.02	$ 1.98	$ 1.85
Pro-forma diluted.	$ 1.99	$ 1.93	$ 1.79

9. Major Customers. The Company had one major retail customer, International Business Machines Corporation ("IBM"), that accounted for 24.1 percent, 25.7 percent, and 26.6 percent of retail MWh sales, and 16.6 percent, 17.3 percent, and 19.2 percent of the Company's retail operating revenues in 2003, 2002 and 2001, respectively.

10. Fair Value of Financial Instruments. The carrying value and fair value of the Company's first mortgage bonds and derivative contracts is summarized in the following table:

Fair Value of Financial Instruments

	As of December 31, 2003		2002	
In thousands	Fair Value	Carrying Value	Fair Value	Carrying Value
Long-Term Debt, net	$ 91,725	$ 92,113	$ 96,215	$ 99,942
Derivatives	19,773	19,773	18,405	18,405

The book value of accounts receivable, accrued utility revenues, other investments, cash surrender value of life insurance, short-term debt, accounts payable, customer deposits and accrued interest approximate fair value due to their short-term, highly liquid nature.

11. 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.

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

13. Derivative Instruments. SFAS 133, as amended, 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, was effective for the Company beginning 2001.

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 the application of SFAS 133 to power supply arrangements that qualify as derivatives. We currently have an arrangement (the "9701 arrangement") that grants Hydro-Quebec an option to call power at prices below current and estimated future market rates. This arrangement is effective through 2015. From time to time, we use forward contracts to hedge the 9701 call option. At December 31, 2003, the Company had a liability of $23.7 million reflecting the fair value of 9701 arrangement, and an asset of $4.0 million, reflecting the fair value of a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"). A corresponding net regulatory asset of $19.7 million is also recorded. At December 31, 2002, the Company had a liability of $27.2 million reflecting the fair value of 9701, and an asset of $8.8 million, reflecting the fair value of the Morgan Stanley Contract. A corresponding net regulatory asset of $18.4 million was also recorded. The Company believes that the net regulatory asset is probable of recovery in future rates. The net regulatory asset is based on current estimates of future market prices that are likely to change by material amounts.

The Morgan Stanley Contract is 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.

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

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

16. Other Comprehensive Income. Other comprehensive loss of $2.4 million, net of a $1.6 million income tax benefit, was recognized during 2002 as a result of a minimum pension funding liability. During 2003, an increase in the market value of pension plan assets allowed a reduction in the minimum pension liability of approximately $587,000, net of $400,000 income tax expense.

17. New Accounting Standards. 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 Company has recognized, as a liability, an asset retirement obligation for accumulated costs of removal, which totaled approximately $21.2 million and $19.9 million at December 31, 2003 and 2002, respectively, and increased plant and equipment balances by the same amount as a result of this accounting pronouncement.

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, did not 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 Company adopted the prospective method of accounting for stock-based compensation under SFAS 148 beginning January 1, 2003. The application of this accounting standard did not materially impact the Company's financial position or results of operations during 2003.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"("SFAS 150"). SFAS 150 establishes standards for classifying and measuring financial instruments with characteristics of both liabilities and equity. The guidance is effective for financial instruments entered into or modified after May 31, 2003. This statement had no effect on our financial position or results of operations during 2003.

In December 2003, the FASB issued Statement of Financial Accounting Standards No. 132 (revised 2003), "Employers" Disclosures about Pensions and Other Postretirement Benefits ("SFAS 132"). In an effort to provide the public with better and more complete information, the standard requires that companies provide more details about their plan assets, benefit obligations, cash flows, benefit costs and other relevant information. The guidance is effective for fiscal years ending December 15, 2003 and for quarters beginning after December 15, 2003. We have adopted all of the disclosures required by the standard.

In January 2003, the FASB issued FASB Interpretation No. ("FIN") 46, " Consolidation of Variable Interest Entities." FIN 46 requires a company to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the company does not have a majority of voting interests. The adoption of FIN 46 did not require the Company to consolidate any variable interest entities.

In January 2003, the FASB issued FIN 45,"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 requires a company to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. The Company adopted the measurement provisions of this statement in the first quarter of 2003 and it did not have an effect on the financial statements during 2003.

The Company provides health care, life insurance, prescription drug and other benefits, to retired employees who meet certain age and years of service requirements. Under certain circumstances, eligible retirees are required to make contributions for postretirement benefits.

In December 2003, the FASB issued Staff Position ("FSP") 106-1, "Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the "Act"). The Act provides for drug benefits for certain retirees under a new Medicare Part D program. For employers like the Company there are subsidies available which are inherent in the Act. The FASB allowed, and the Company elected, a one-time deferral of the recognition of the impact of the Act in the employer's accounting until formal guidance is issued. As a result, the provisions of the Act are not reflected in the other postretirement benefits disclosure (See Note H). The issuance of formal accounting guidance may require a change to previously reported information.

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,	
	2003	2002	2003	2002
			(IN THOUSANDS)	
VELCO-common	28.41%	28.41%	$ 2,469	$ 2,309
VELCO-preferred.	30.00%	30.00%	246	305
Total VELCO			2,715	2,614
Vermont Yankee- Common	33.60%	18.99%	1,605	9,721
New England Hydro Transmission-Common. .	3.18%	3.18%	592	660
New England Hydro Transmission Electric- Common	3.18%	3.18%	984	1,106
Total investment in associated companies			$ 5,896	$14,101

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 $12.0 million, $12.7 million, and $11.5 million for the years 2003, 2002 and 2001, 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. The Company plans to make capital investments of up to $20 million in VELCO through 2007 in support of various transmission projects.

Summarized unaudited financial information for VELCO is as follows:

At and for the years ended December 31,

2003	2002	2001
(In thousands)		

Net income	$ 1,270	$ 1,094	$ 1,118
Company's equity in net income	$ 418	$ 319	$ 308
Total assets	$ 126,793	$106,613	$89,322
Less:			
Liabilities and long-term debt	117,393	97,417	81,335
Net assets	$ 9,400	$ 9,196	$ 7,987
Company's equity in net assets	$ 2,715	$ 2,614	$ 2,352

VERMONT YANKEE. On July 31, 2002, Vermont Yankee Nuclear Power Corporation ("VY" or "Vermont Yankee") announced that the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("ENVY") 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 ENVY, 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 received a credit from VY and has requested permission from the VPSB to apply the credit to reduce the $2.0 million regulatory asset.

The Company's ownership share of VY has increased from approximately 19.0 percent in 2002 to approximately 33.6 percent currently, due to VY's purchase of certain minority shareholders' interests. The Company's entitlement to energy produced by the ENVY nuclear plant remains at approximately 20 percent of plant production.

The 2003 decrease in equity in net assets of VY resulted from a distribution of proceeds, in the form of dividends to VY owners, from the sale of the VY nuclear power plant.

Summarized unaudited financial information for Vermont Yankee is as follows:

At and for the years ended December 31,

	2003	2002	2001
		(In thousands)	
Earnings:			
Operating revenues.	$187,123	$ 175,722	$178,840
Net income applicable to common stock	2,536	9,454	6,119
Company's equity in net income. . . .	$ 498	$ 1,745	$ 1,131
Total assets.	$150,720	$ 201,426	$723,815
Less:			
Liabilities and long-term debt. . . .	145,946	150,413	669,640
Net Assets.	$ 4,774	$ 51,203	$ 54,175
Company's equity in net assets.	$ 1,605	$ 9,721	$ 9,725

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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, 2003. The Company also funds an Employee Savings and Investment Plan ("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, or its subsidiaries. Outstanding options become exercisable at between one and four years after the grant date and remain exercisable until 10 years from the grant date.

Prior to 2003, as permitted by Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation ("SFAS 123"), the Company had 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 issued through 2002. Under APB 25, because the exercise price equals the market price of the underlying stock on the date of grant, no compensation expense was recorded. Effective January 1, 2003, the Company elected to expense the fair value of options granted beyond that date. The amount of expense recorded during 2003 was immaterial. Options have been issued only to employees and directors.

The fair values of the options granted in 2003, 2002, and 2001 are $1.33, $2.27, and $4.16 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, 2003:

Plan year	Weighted average exercise price	Outstanding options	Assumptions used in option pricing model: Remaining Contractual Life	Risk Free Interest rate	Expected Life in Years	Expected Stock Volatility	Dividend Yield
2000.	$ 7.90	192,200	6.6	6.05%	5	30.58	4.5%
2001.	$16.72	35,150	7.6	5.25%	6	32.69	4.0%
2002.	$17.84	69,500	8.6	4.50%	6.5	16.89	4.5%
2003.	$20.55	4,000	9.3	2.48%	6	13.68	4.5%
Total	$11.39	300,850					

Options granted are not exercisable until one year after the date of grant.

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, 2003	2002	2001

	(in thousands)		
Net income (loss) before preferred dividends	$ 10,407	$11,494	$11,611
Preferred stock dividend requirement	3	96	933
Net income (loss) applicable to common stock	$ 10,404	$11,398	$10,678
Average number of common shares-basic. . . .	4,980	5,592	5,630
Dilutive effect of stock options	160	164	159
Average number of common shares-diluted. . .	5,140	5,756	5,789

	Total Options	Weighted Average Price	Range of Exercise Prices	Options Exercisable
Outstanding at December 31, 2000	331,900	$ 7.90	$ 7.90-$7.90	0
Granted.	55,450	16.67	$14.50-$16.78	
Granted.	1,000	12.28	$12.28-$12.28	
Exercised.	17,400	7.90	$ 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-$18.67	
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
Granted.	4,000	20.55	$20.22-$22.62	
Exercised.	64,550	10.63	$ 7.90-$18.67	
Forfeited.	4,400	17.36	$16.78-$18.12	
Outstanding at December 31, 2003	300,850	$11.39	$ 7.90-$22.62	193,700

As part of our long-term stock incentive program, 13,300 shares of unrestricted common stock were granted to employees other than the Company's executives during December 2003, resulting in compensation expense of approximately $300,000. Directors were granted 8,800 deferred stock units during 2003, resulting in compensation expense of approximately $196,000. The Company also granted 35,200 deferred stock units to senior management on February 9, 2004. Each deferred stock unit is convertible into one share of common stock. The total market value of the shares will be charged to compensation expense over a two-year vesting period.

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 $19.9 million of retained earnings were free of restrictions at December 31, 2003.

D. PREFERRED STOCK

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 repurchased the remaining $0.2 million of the 9.375 percent Class D preferred stock outstanding. All remaining preferred stock was repurchased during 2003.

E. SHORT-TERM DEBT

The Company has a $20.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by Sovereign Bank ("Sovereign"), expiring June 2004 (the "Fleet-Sovereign Agreement"). The Fleet-Sovereign 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 $500,000 outstanding at a weighted average rate of 4 percent under the Fleet-Sovereign Agreement at December 31, 2003. There was no non-utility short-term debt outstanding at December 31, 2003 or 2002.

The Fleet-Sovereign Agreement requires the Company to certify on a quarterly basis that it has not suffered a "material adverse change". The agreement also requires the Company to comply with certain covenants. The Company was in compliance with all covenants at December 31, 2003.

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 for both December 31, 2003 and 2002. 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, 2003, are:

	Sinking Fund and Maturities
2004	$ -
2005	-
2006	14,000
2007	-
2008	-
Thereafter	79,000
Total Long-term debt	$ 93,000

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, 2003 and 2002, the net regulatory assets were $924,000 and $1,042,000, 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, 2003 and December 31, 2002, were as follows:

	AT DE
	2003
	(In thousan
DEFERRED TAX ASSETS	
Contributions in aid of construction	$ 11
Deferred compensation and postretirement benefits	5
Self insurance and other reserves	
Other	1
	$ 18
DEFERRED TAX LIABILITIES	
Property related	$ 43
Demand side management	1
Deferred purchased power costs	
Pine Street reserve	2
Other	3
	$ 52
Net accumulated deferred income tax liability	$ 34

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 DEC	
	2003	2002
	(In thousands	
Net change in deferred income tax liability	$ 7,539	$ 2,71
Change in income tax related regulatory assets and liabilities	(6,175)	2,75
Change in tax effect of accumulated other comprehensive income	398	(1,61
Deferred income tax expense (benefit)	$ 1,761	$ 3,85

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

	YEARS ENDED DECEMBER 31, 2003	2002	2001
	(In thousands)		
Current federal income taxes.	$ 2,434	$1,873	$ 7,846
Current state income taxes. .	1,207	593	2,418
Total current income taxes. .	3,641	2,466	10,264
Deferred federal income taxes	1,307	2,920	(2,296)
Deferred state income taxes .	454	939	(738)
Total deferred income taxes .	1,761	3,859	(3,034)
Investment tax credits-net. .	(282)	(282)	(282)
Income tax expense.	$ 5,120	$6,043	$ 6,948

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

	YEARS ENDED DECEMBER 31, 2003	2002	2001
	(In thousands)		
Income before income taxes and preferred dividends.	$ 15,527	$17,537	$18,559
Federal statutory rate	34.0%	34.0%	35.0%
Computed "expected" federal income taxes.	5,279	5,963	6,496
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation	41	41	45
Dividends received and paid credit	(465)	(575)	(440)
AFUDC-equity funds	(129)	(80)	(72)
Amortization of ITC.	(282)	(282)	(282)
State tax.	797	1,011	1,705
Excess deferred taxes.	(60)	(60)	(60)
Tax attributable to subsidiaries	(25)	(31)	63
Other.	(36)	56	(507)
Total federal and state income tax	$ 5,120	$ 6,043	$ 6,948
Effective combined federal and state income tax rate.	33.0%	34.5%	37.4%

NON-UTILITY. The Company's non-utility subsidiaries, excluding Northern Water Resources, Inc. ("NWR"), had accumulated deferred income taxes of approximately $2,000 on their balance sheets at December 31, 2003, attributable to depreciation timing differences.

The components of the provision for the income tax expense (benefit) for the non-utility operations were not significant.

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, 2003, 2002 and 2001. 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 equity securities, fixed income securities, hedge funds and cash equivalent funds.

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 to meet or exceed the minimum funding requirements of ERISA or Pension Benefit Guaranty Corporation, 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 during 2002 and made voluntary contributions totaling $3.5 million during 2003. The Company currently plans to contribute between $2.0 and $3.0 million of additional funds during 2004. The Company's pension costs and cash funding requirements could increase in future years in the absence of further recovery in the equity markets.

During 2002, the Company's retirement plan asset return experience required the Company to recognize a minimum pension liability of $4.0 million, and a $1.6 million tax benefit, as prescribed by generally accepted accounting principles. Common equity was reduced in the amount of $2.4 million through a charge to other comprehensive income.

During 2003, market value appreciation of pension plan investments resulted in the reduction of the previously recognized minimum pension liability to $3.0 million. Common equity increased approximately $587,000, net of applicable income tax, through a credit to other comprehensive income.

Accrued postretirement health care expenses are recovered in rates. 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, 2003 and 2002.

	At and for the years ended December 31,			
	Pension Benefits		Other Postretirement Be	
	2003	2002	2003	2002
	(In thousands)			
Change in projected benefit obligation:				
Projected benefit obligation as of prior year end.	$ 29,937	$25,895	$ 20,707	$ 16,49

Service cost	755	668	496	29
Interest cost.	1,900	1,849	1,316	1,11
Participant contributions.	-	-	136	14
Plan change.	-	-	(1,812)	
Change in actuarial assumptions.	292	-	2,095	
Actuarial (gain) loss.	2,789	3,230	(25)	3,61
Benefits paid.	(1,629)	(1,650)	(1,007)	(96
Administrative expense	(64)	(55)	-	
Projected benefit obligation as of year end. . . .	$ 33,980	$29,937	$ 21,906	$ 20,70
Change in plan assets:				
Fair value of plan assets as of prior year end . .	$ 21,104	$24,341	$ 8,760	$ 10,01
Administrative expenses paid	(64)	(55)	-	
Participant contributions.	-	-	136	14
Employer contributions	3,500	1,000	782	81
Actual return on plan assets	4,956	(2,532)	1,558	(1,25
Benefits paid.	(1,629)	(1,650)	(1,007)	(96
Fair value of plan assets as of year end	$ 27,867	$21,104	$ 10,229	$ 8,76
Funded status as of year end	$ (6,113)	$(8,833)	$(11,677)	$(11,94
Unrecognized transition obligation (asset)	-	(77)	2,952	3,28
Unrecognized prior service cost.	984	839	(2,216)	(46
Unrecognized net actuarial loss.	6,372	6,982	9,250	8,37
Prepaid (accrued) benefits at year end	$ 1,243	$(1,089)	$ (1,691)	$ (75

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31, 2003, 2002, and 2001 were $392,000, $408,000, and $340,000, 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 Postretirem	
	2003	2002	2001	2003	2002
	(In thousands)				
Service cost	$ 755	$ 668	$ 537	$ 496	$ 296
Interest cost.	1,900	1,849	1,737	1,316	1,119
Expected return on plan assets	(1,851)	(2,112)	(2,379)	(740)	(851)
Amortization of transition asset	(77)	(164)	(164)		-
Amortization of prior service cost	147	147	147	(58)	(58)
Amortization of the transition obligation.	-	-	-	328	328
Recognized net actuarial gain.	294	-	(237)	381	60
Net periodic benefit cost (income) . .	$ 1,168	$ 388	$ (359)	$1,723	$ 894

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

Assumptions used in benefit obligation measurement

	For the years ended December 31,			
	Pension benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Weighted average assumptions as of year end:				
Discount rate.	6.00%	6.50%	6.00%	6.50%
Expected return on plan assets	8.50%	9.00%	8.50%	8.50%
Rate of compensation increase.	4.25%	4.25%	4.25%	4.25%
Medical inflation.	-	-	9.25%	10.00%

Assumptions used in periodic cost measurement

	For the years ended December 31,			
	Pension benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Weighted average assumptions as of year end:				
Discount rate.	6.50%	7.00%	6.50%	7.00%
Expected return on plan assets	8.50%	9.00%	8.50%	8.50%
Rate of compensation increase.	4.25%	4.25%	4.25%	4.25%
Medical inflation.	-	-	10.00%	7.50%

For measurement purposes, a 9.25 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, 2003 by $4.8 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2003 by $434,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2003 by $3.8 million, and the total of the service and interest cost components of net periodic postretirement cost for 2003 by $339,000.

The Company's defined benefit plan investment policy seeks to achieve sufficient growth to enable the pension plan to meet its future obligations and to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 65 percent of plan assets be invested in equity securities, 30 percent of plan assets be invested in debt securities and the remainder be invested in alternative investments.

The Company expects an annual long-term return for the defined benefit plan asset portfolios of 8.25 percent, based on a representative allocation within the target asset allocation described above. In formulating this assumed rate of return, the Company considered historical returns by asset category and expectations for future returns by asset category based, in part, on expected capital market performance of the next ten years.

Pension Assets

Weighted Average Asset Allocation	For the years ended December 31,		
	2004 TARGET	2003	2002
Asset Category			
Equity Securities . . .	65.00%	63.10%	59.61%
Debt Securities	30.00%	24.92%	31.65%
Real Estate	0.00%	0.00%	0.00%
Other	0.00%	6.60%	8.74%
Alternative investments	5.00%	5.38%	0.00%
total	100.00%	100.00%	100.00%

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 deregulation in Vermont. Legislation has been introduced in the Vermont legislature that would permit (but not require) the Company to negotiate with individual customers to permit such customers to procure their own electric power supply requirements, subject to VPSB approval. We cannot predict whether this legislation will be enacted. If enacted, the Company would not negotiate any such arrangement unless in the Company's estimation, the arrangement assured the Company of full recovery of any resulting stranded costs and that the Company's financial condition would not otherwise be adversely affected. 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. 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.

PINE STREET BARGE CANAL SUPERFUND SITE - In 1999 the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal superfund site in Burlington, Vermont, known as the Pine Street Barge Canal. The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. In 2003, the Company expended $2.6 million to cover its obligations under the consent decree and we have estimated total future costs of the Company's net future obligations through 2033 under the consent decree to be $8.5 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have also recorded a regulatory asset of $13.0 million to reflect future recovery of these costs, as well as past unrecovered costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company will begin to amortize past unrecovered costs in 2005. The Company will amortize the full amount of these costs, as they are incurred, over 20 years without a return. The amortization will be allowed in future rates, without disallowance or adjustment, until fully amortized.

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, 2003, as follows:

	Ownership Interest	Share of Capacity	Share of Utility Plant	Share of Accumulated Depreciation
	(In %)	(In MWh)	(In thousands)	
Highgate	33.8	67.6	$ 10,296	$ 4,926
McNeil	11.0	5.9	8,989	5,379
Stony Brook (No. 1). . .	8.8	31	10,377	8,965
Wyman (No. 4).	1.1	6.8	1,980	1,380
Metallic Neutral Return.	59.4	-	1,563	806

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 - On December 22, 2003, the VPSB approved a three-year rate plan (the "2003 Rate Plan") jointly proposed earlier in the year by the Company and the Department. The 2003 Rate Plan, as approved, covers the period through 2006 and includes the following principal elements.

The Company's rates will remain unchanged through 2004. The 2003 Rate Plan allows the Company to raise rates 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. If the Company's cost of service filings in 2005 or 2006 establish that a lesser rate increase in required for the Company to meet its revenue requirements, the Company will implement the lesser rate increase.

The Company may seek additional rate increases in extraordinary circumstances, such as severe storm repair costs, natural disasters, extended unanticipated unit outages, or significant losses of customer load.

The Company's allowed return on equity is reduced from 11.25 percent to 10.5 percent, for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on core utility operations are capped at 10.5 percent. If excess earnings result in 2004, they will be applied to reduce regulatory assets. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.

The Company will carry forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003 from the Company's 2001 rate case settlement summarized below. The Company will amortize (recover) certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, beginning in January 2005, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

The Company will file with the VPSB in early 2004 a new fully allocated cost of service study and rate re-design, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design will be subject to VPSB approval.

The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted in Vermont in 2003. The target for filing such a plan is April 2004. If the Company and Department agree on such a plan, and it is approved by the VPSB, the alternative regulation plan would supersede the 2003 Rate Plan.

In January 2001, the VPSB approved a rate case settlement between the Company and the Department (the "2001 Settlement Order"). The final settlement, as approved, included the following:

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

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.

5. DEFERRED CHARGES NOT INCLUDED IN RATE BASE.

The Company has incurred and deferred approximately $11.1 million in costs for Pine Street, tree trimming, storm damage, and regulatory commission work of which approximately $408,000 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 amounts deferred. Management expects to recover these costs over periods ranging from five to twenty years beginning January 1, 2005, pursuant to the 2003 Rate Plan. The 2001 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 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.

In November 2003, Rockingham notified the Company that the town intended to initiate proceedings before the town selectboard to condemn the Company's distribution and associated property located within the town. The Company sought and obtained in December 2003 a preliminary injunction from the State Superior Court prohibiting the town from proceeding with condemnation before the selectboard. The Company successfully argued that Vermont law required Rockingham to pursue any such municipalization effort by petition to the VPSB, which is required to determine both the fair value of any assets subject to municipalization and the amount of damages to the utility caused by severance of the property subject to municipalization. The preliminary injunction remains in effect and Rockingham has not filed any petition with the VPSB seeking to municipalize assets. 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.

7. OTHER LEGAL MATTERS.

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 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 in connection with this proceeding.

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, 2003, the present value of the Company's obligation is approximately $4.6 million.

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

Year ending	December 31 (In thousands)
2004.	$ 387
2005.	387
2006.	387
2007.	387
2008.	387
Total for 2009-2015	2,712
Total	$ 4,647

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company and New England Hydro-Transmission Corporation, subsidiaries of National Grid USA. Certain of the Phase II participating utilities, including the Company, own equity interests in such companies. The Company holds approximately 3.2 percent of the equity of the corporations owning the Phase II facilities and accounts for its ownership under the equity method of accounting.

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 2003 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	$ 128
	Other debt service	444
	Other capacity	535
Total annual capacity		$ 1,107
Company's share of long-term debt		$ 1,817

2. VERMONT YANKEE

The Company has a long-term power purchase contract with VY, which sold its nuclear power plant to ENVY on July 31, 2002. The Company is no longer required to pay its proportionate share of fixed costs associated with the ENVY 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 ENVY also calls for ENVY, 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.

A summary of the Purchase Power Agreement, 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	2003	$ 37,288
	estimated 2004-2015	$ 32,377
Average cost per KWh	2003	$ 0.042
	estimated 2004-2015	$ 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 ENVY to finalize the VY sale.

The Company received its share of the VY power plant sale proceeds, approximately $8.2 million, during October 2003, and used the proceeds to retire debt.

3. HYDRO-QUEBEC

Under various contracts, summarized 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 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 increased power supply expense during 2003 by approximately $1.2 million.

During 2003, Hydro-Quebec exercised its second option to reduce the load factor for 2004, and we expect Hydro-Quebec to exercise its third option in 2004 for deliveries occurring principally during 2005. Hydro-Quebec also 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. Under the 1987 Contract, Vermont joint owners, including the Company, have two remaining options to adjust deliveries by a five percent load factor. These cannot be used to offset Hydro-Quebec's reductions through 2005, but may be used after 2005 to manage power supply costs.

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, including historic and projected charges for the years indicated, follows:

			THE 1987 CONTRACT SCHEDULE B		SCHE
			(Dollars in thousands except per KWh)		
Capacity acquired			68 MW		
Contract period			1995-2015		
Minimum energy purchase (annual load factor)			65%-75%		
Annual energy charge	2003	$	10,565		$
	estimated 2004-2015		13,756	(1)	
Annual capacity charge	2003	$	16,857		$
	estimated 2004-2015	$	17,122	(1)	$
Average cost per KWh	2003	$	0.071		$
	estimated 2004-2015	$	0.064	(2)	$

(1) Estimated average includes load factor reduction to 65 percent in 2004
(2) Estimated average in nominal dollars levelized over the period indicated includes amortization of payments to Hydro-Quebec

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 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, 2003, Hydro-Quebec had purchased or called to purchase 513,000 MWh under option B.

In 2003, Hydro-Quebec exercised option A and option B, and called for delivery to third parties at a net expense to the Company of approximately $4.5 million, including capacity charges.

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.

The Company believes that it is probable that Hydro-Quebec will call options A and B for 2004, and has purchased replacement power at an incremental cost of $3.2 million. The Company has also covered 54 percent of expected calls during 2005 at an incremental cost of $1.1 million.

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.

Beginning January 1, 2004, the Company will reduce the power that it sells to MS. The reduction in sales is expected to reduce wholesale revenues by approximately $65 million, and power supply expense by a similar amount. The Company does not expect the change to adversely affect its opportunity to earn its allowed rate of return during 2004.

The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. The MS contract is a derivative that includes a risk premium above expected future costs of electricity.

L. DISCONTINUED OPERATIONS.

The Company has 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 net reserve for loss from discontinued operations reflects management's current estimate. The residual operations earned $0.01 per share in 2003 and $0.02 per share in 2002, primarily as a result of adjustments to a reserve for warranty claims. At December 31, 2003, 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 against NWR. The ultimate loss remains subject to the disposition of remaining assets and liabilities, and could exceed the amounts recorded. The following illustrates the results and financial statement impact of discontinued operations during and at the periods shown:

	2003	2002	2001
	(In thousands except per share)		
Revenues	$ -	$ 88	$ 156
Gain (loss) on disposal.	79	99	(182)
Net income (loss).	$ 79	$ 99	$ (182)
Net income (loss) per share-basic.	$ 0.01	$ 0.02	$(0.03)
Proceeds from asset sales.	$ -	$ -	$ -
Total assets	$ 1,488	$1,622	$2,700
State income taxes	$ 12	$ 19	$ (175)
Federal income taxes	39	52	(550)
Investment tax credits	-	-	-
Income tax expense (benefit) . . .	$ 51	$ 71	$ (725)

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.

2003 Quarter ended	MARCH	JUNE	SEPTEMBER	DECEMBER	TOTAL
(Amounts in thousands except per share data)					
Operating revenues	$72,945	$64,455	$ 71,975	$ 71,095	$280,4
Operating income	5,231	2,425	4,302	3,348	15,3
Net income-continuing operations	$ 4,084	$ 1,120	$ 3,034	$ 2,087	$ 10,3
Net income-discontinued operations	(13)	(8)	6	94	
Net Income applicable to common stock.	$ 4,071	$ 1,112	$ 3,040	$ 2,181	$ 10,4
Basic earnings per share from:					
Continuing operations.	$ 0.82	$ 0.22	$ 0.61	0.43	$ 2.
Discontinued operations.	-	-	-	0.01	0.

Basic earnings per share	$ 0.82	$ 0.22	$ 0.61	$ 0.44	$ 2.
Weighted average common shares outstanding	4,959	4,969	4,982	5,009	4,9
Diluted earnings per share from:					
Continuing operations	$ 0.80	$ 0.22	$ 0.59	0.40	$ 2.
Discontinued operations	-	-	-	0.01	0.
Diluted earnings per share	$ 0.80	$ 0.22	$ 0.59	$ 0.41	$ 2.
Weighted average common and common equivalent. shares outstanding	5,118	5,129	5,141	5,165	5,1

2002	Quarter ended MARCH	JUNE	SEPTEMBER	DECEMBER	TOTAL
(Amounts in thousands except per share data)					
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	5,756
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 MARCH	JUNE	SEPTEMBER	DECEMBER	TOTA
(Amounts in thousands except per share data)					
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	

Independent Auditors' Report
To the Board of Directors of
Green Mountain Power Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Green Mountain Power Corporation and subsidiaries (the Company) as of December 31, 2003, and 2002, and the related consolidated statements of income, comprehensive income, changes in stockholders equity and cash flows for each of the two years in the period ended December 31, 2003. The financial statements of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 and for the year 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 audits in accordance with auditing standards generally accepted in the United States of America. 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 financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the two years then ended in conformity with accounting principles generally accepted in the United States.

Deloitte & Touche, LLP
/s/Deloitte & Touche, LLP
Boston, Massachusetts
February 25, 2004

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, 2003, 2002, and 2001

	Balance at Beginning of Period	Additions Charged to Cost & Expenses	Additions Charged to Other Accounts	De
Injuries and Damages (1)				

2003	$10,489,506	(521,493)	-	1
2002	12,064,548	325,000	134,505	2
2001	13,382,713	212,555	312,229	1

Allowance for Doubtful Accounts

2003	547,316	143,214	-
2002	575,890	-	37,270
2001	425,890	150,000	

(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, 2003 and 2002 and for each of the two years in the period ended December 31, 2003, and have issued our report thereon dated February 25, 2004; such report is included elsewhere in this Form 10-K. Our audit also included the 2003 and 2002 information included in the financial statement schedule 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 audits. In our opinion, such 2003 and 2002 information included in the 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. The financial statement schedule of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 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.

/s/DELOITTE & TOUCHE LLP
Boston, MA
February 25, 2004

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.

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 year ended December 31, 2001 did not contain any qualification, modification, or disclaimers.

ITEM 9A. CONTROLS AND PROCEDURES

Pursuant to Rule 13a-15(b) under the Securities and Exchange Act of 1934, we carried out an evaluation, with the participation of our management, including Christopher L. Dutton, President and Chief Executive Officer and Robert J. Griffin, Chief Financial Officer, Vice President and Treasurer (principal financial officer), of the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, our President and Chief Executive Officer, and our Chief Financial Officer, Vice President and Treasurer (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 has been no change in our internal control over financial reporting during the quarter ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 20, 2004. 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 2004.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Fees Paid to Deloitte & Touche

During the fiscal year ended December 31, 2003, Deloitte & Touche was employed principally to perform the annual audit and to render other services. Fees paid to Deloitte & Touche for services rendered in fiscal years 2002 and 2003 are listed in the following table.

Years ended December 31,

	2003	2002
Audit Fees	$160,471	$162,484
Audit-Related Fees	7,000	-
Tax Services Fees.	36,577	54,147
All other fees	-	-
Total Deloitte and Touche fees	$204,048	$216,631

Fees paid during 2002 include audit fees of $9,000 and tax fees of $6,050 paid to Arthur Andersen for services rendered during 2002.

Audit Fees include fees for services performed to comply with Generally Accepted Auditing Standards (GAAS), including the recurring audit of the Company's financial statements. This category also includes fees for audits provided in connection with statutory filings or services that generally only the principal auditor reasonably can provide to a client, such as procedures related to audit of income tax provisions and related reserves, consents and assistance with and review of documents filed with the Securities and Exchange Commission.

Audit-Related Fees include fees associated with assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements. This category includes fees related to assistance with implementation of the new Securities and Exchange Commission and Sarbanes-Oxley Act of 2002 requirements. Audit-related fees also include audits of employee benefit plans.

Tax Fees primarily include fees associated with tax audits, tax compliance, tax consulting, as well as tax planning.

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:

On December 23, 2003, a Form 8-K filing announced the VPSB approval of a Memorandum of Understanding with the DPS regarding rate stability, rate increases, and the amortization of the Pine Street Barge Canal costs.

On December 10, 2003, a Form 8-K filing announced that the Board of Directors had approved changes to the Company's Bylaws.

On December 3, 2003, a Form 8-K filing announced a presentation by Christopher L. Dutton, the President and CEO, and Robert J. Griffin, CFO, at an electric industry conference entitled "Investing in the Electric Utilities Industry".

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

ITEM 15(A)3 AND ITEM 15C. EXHIBITS SEC DOCKET

, INCORPORATED BY

EXHIBIT NUMBER	DESCRIPTION	REFERENCE OR EXHIBIT	PAGE FI
3-A	RESTATED ARTICLES OF ASSOCIATION, AS CERTIFIED . . . . JUNE 6, 1991.	3-A	FORM 10-K
3-A-1	AMENDMENT TO 3-A ABOVE, DATED AS OF MAY 20, 1993..	3-A-1	FORM 10-K
3-A-2	AMENDMENT TO 3-A ABOVE, DATED AS OF OCTOBER 11, 1996..	3-A-2	FORM 10-Q
3-B	BY-LAWS OF THE COMPANY, AS AMENDED . . . . FEBRUARY 10, 1997.	3-B	FORM 10-K
3-C	BY-LAWS OF THE COMPANY, AS AMENDED . . . . DECEMBER 8, 2004	3-C	FORM 8-K
4-B-1	INDENTURE OF FIRST MORTGAGE AND DEED OF TRUST. . . . . DATED AS OF FEBRUARY 1, 1955.	4-B	
4-B-2	FIRST SUPPLEMENTAL INDENTURE DATED AS OF	4-B-2	

	APRIL 1, 1961.		
4-B-3	SECOND SUPPLEMENTAL INDENTURE DATED AS OF. . . . . JANUARY 1, 1966.	4-B-3	
4-B-4	THIRD SUPPLEMENTAL INDENTURE DATED AS OF . . . . JULY 1, 1968.	4-B-4	
4-B-5	FOURTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . OCTOBER 1, 1969.	4-B-5	
4-B-6	FIFTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . DECEMBER 1, 1973.	4-B-6	
4-B-7	SEVENTH SUPPLEMENTAL INDENTURE DATED AS. . . . . AUGUST 1, 1976.	4-A-7	
4-B-8	EIGHTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . DECEMBER 1, 1979.	4-A-8	
4-B-9	NINTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . JULY 15, 1985.	4-B-9	
4-B-10	TENTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . JUNE 15, 1989.	4-B-10	FORM 10-K
4-B-11	ELEVENTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . SEPTEMBER 1, 1990.	4-B-11	FORM 10-Q
4-B-12	TWELFTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . MARCH 1, 1992.	4-B-12	FORM 10-K
4-B-13	THIRTEENTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . MARCH 1, 1992.	4-B-13	FORM 10-K
4-B-14	FOURTEENTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . NOVEMBER 1, 1993.	4-B-14	FORM 10-K
4-B-15	FIFTEENTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . NOVEMBER 1, 1993.	4-B-15	FORM 10-K
4-B-16	SIXTEENTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . DECEMBER 1, 1995.	4-B-16	FORM 10-K
4-B-17	REVISED FORM OF INDENTURE AS FILED AS AN EXHIBIT . . . . TO REGISTRATION STATEMENT NO. 33-59383.	4-B-17	FORM 10-Q
4-B-18	CREDIT AGREEMENT BY AND AMONG GREEN MOUNTAIN POWER . . . . . . THE BANK OF NOVA SCOTIA, STATE STREET BANK AND TRUST COMPANY, FLEET NATIONAL BANK, AND FLEET NATIONAL BANK, AS AGENT	4-B-18	FORM 10-K
4-B-18(A)	AMENDMENT TO EXHIBIT 4-B-18.	4-B-18(A)	FORM 10-Q
4-B-19	SEVENTEENTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . DECEMBER 1, 2002	4-B-19	FORM 10-K
10-A	FORM OF INSURANCE POLICY ISSUED BY PACIFIC . . . . INSURANCE COMPANY, WITH RESPECT TO INDEMNIFICATION OF DIRECTORS AND OFFICERS.	10-A	
10-B-1	FIRM POWER CONTRACT DATED SEPTEMBER 16, 1958,. . . . . BETWEEN THE COMPANY AND THE STATE OF VERMONT AND SUPPLEMENTS THERETO DATED SEPTEMBER 19, 1958; NOVEMBER 15, 1958; OCTOBER 1, 1960 AND FEBRUARY 1, 1964.	13-B	
10-B-2	POWER CONTRACT, DATED FEBRUARY 1, 1968, BETWEEN THE COMPANY. . AND VERMONT YANKEE NUCLEAR POWER CORPORATION.	13-D	
10-B-3	AMENDMENT, DATED JUNE 1, 1972, TO POWER CONTRACT . . . . BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION.	13-F-1	
10-B-3(A)	AMENDMENT, DATED APRIL 15, 1983, TO POWER. . . . . CONTRACT BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION.	10-B-3(A)	
10-B-3(B)	ADDITIONAL POWER CONTRACT, DATED . . . . FEBRUARY 1, 1984,BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION.	10-B-3(B)	
10-B-4	CAPITAL FUNDS AGREEMENT, DATED FEBRUARY 1, ... 1968, BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION.	13-E	
10-B-5	AMENDMENT, DATED MARCH 12, 1968, TO CAPITAL.	13-F	

	FUNDS AGREEMENT BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION.	
10-B-6	GUARANTEE AGREEMENT, DATED NOVEMBER 5, 1981, OF THE. . . . . . COMPANY FOR ITS PROPORTIONATE SHARE OF THE OBLIGATIONS OF VERMONT YANKEE NUCLEAR POWER CORPORATION UNDER A $40 MILLION LOAN ARRANGEMENT.	10-B-6
10-B-7	THREE-PARTY POWER AGREEMENT AMONG THE COMPANY, ... VELCO AND CENTRAL VERMONT PUBLIC SERVICE CORPORATION DATED NOVEMBER 21, 1969.	13-I
10-B-8	AMENDMENT TO EXHIBIT 10-B-7, DATED JUNE 1, 1981.	10-B-8
10-B-9	THREE-PARTY TRANSMISSION AGREEMENT AMONG THE . . . . COMPANY, VELCO AND CENTRAL VERMONT PUBLIC SERVICE CORPORATION, DATED NOVEMBER 21, 1969.	13-J
10-B-10	AMENDMENT TO EXHIBIT 10-B-9, DATED JUNE 1, 1981.	10-B-10
10-B-14	AGREEMENT WITH CENTRAL MAINE POWER COMPANY ET. . . . . AL, TO ENTER INTO JOINT OWNERSHIP OF WYMAN PLANT, DATED NOVEMBER 1, 1974.	5.16
10-B-15	NEW ENGLAND POWER POOL AGREEMENT AS AMENDED TO . . . . NOVEMBER 1, 1975.	4.8
10-B-16	BULK POWER TRANSMISSION CONTRACT BETWEEN THE . . . . COMPANY AND VELCO DATED JUNE 1, 1968.	13-V
10-B-17	AMENDMENT TO EXHIBIT 10-B-16, DATED JUNE 1, 1970..	13-V-I
10-B-20	POWER SALES AGREEMENT, DATED AUGUST 2, 1976, AS. . . . . AMENDED OCTOBER 1, 1977, AND RELATED TRANSMISSION AGREEMENT, WITH THE MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY.	10-B-20
10-B-21	AGREEMENT DATED OCTOBER 1, 1977, FOR JOINT OWNERSHIP,. . . . . CONSTRUCTION AND OPERATION OF THE MMWEC PHASE I INTERMEDIATE UNITS, DATED OCTOBER 1, 1977	10-B-21
10-B-28	CONTRACT DATED FEBRUARY 1, 1980, PROVIDING FOR . . . . THE SALE OF FIRM POWER AND ENERGY BY THE POWER AUTHORITY OF THE STATE OF NEW YORK TO THE VERMONT PUBLIC SERVICE BOARD.	10-B-28
10-B-30	BULK POWER PURCHASE CONTRACT DATED APRIL 7,. . . . . 1976, BETWEEN VELCO AND THE COMPANY.	10-B-32
10-B-33	AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT. . . . . . DATED AS OF DECEMBER 1, 1981, PROVIDING FOR USE OF TRANSMISSION INTER-CONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC.	10-B-33
10-B-34	PHASE I TRANSMISSION LINE SUPPORT AGREEMENT. . . . . DATED AS OF DECEMBER 1, 1981, AND AMENDMENT NO. 1 DATED AS OF JUNE 1, 1982, BETWEEN VETCO AND PARTICIPATING NEW ENGLAND UTILITIES FOR CONSTRUCTION, USE AND SUPPORT OF VERMONT FACILITIES OF TRANSMISSION INTERCONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC.	10-B-34
10-B-35	PHASE I TERMINAL FACILITY SUPPORT AGREEMENT. . . . . DATED AS OF DECEMBER 1, 1981, AND AMENDMENT NO. 1 DATED AS OF JUNE 1, 1982, BETWEEN NEW ENGLAND ELECTRIC TRANSMISSION CORPORATION AND PARTICIPATING NEW ENGLAND UTILITIES FOR CONSTRUCTION, USE AND SUPPORT OF NEW HAMPSHIRE FACILITIES OF TRANSMISSION INTERCONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC.	10-B-35
10-B-36	AGREEMENT WITH RESPECT TO USE OF QUEBEC. . . . . INTERCONNECTION DATED AS OF DECEMBER 1, 1981, AMONG PARTICIPATING NEW ENGLAND UTILITIES FOR USE OF TRANSMISSION INTERCONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC.	10-B-36
10-B-39	VERMONT PARTICIPATION AGREEMENT FOR QUEBEC . . . . INTERCONNECTION DATED AS OF JULY 15, 1982, BETWEEN VELCO AND PARTICIPATING VERMONT	10-B-39

	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.		
10-B-40	VERMONT ELECTRIC TRANSMISSION COMPANY, INC.. . . . . CAPITAL FUNDS AGREEMENT DATED AS OF JULY 15, 1982, BETWEEN VETCO AND VELCO FOR VELCO TO PROVIDE CAPITAL TO VETCO FOR CONSTRUCTION OF THE VERMONT FACILITIES OF THE TRANSMISSION INTER-CONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC.	10-B-40	
10-B-41	VETCO CAPITAL FUNDS SUPPORT AGREEMENT DATED AS . . . . OF JULY 15, 1982, BETWEEN VELCO AND PARTICIPATING VERMONT UTILITIES FOR ALLOCATION OF VELCO'S OBLIGATION TO VETCO UNDER THE CAPITAL FUNDS AGREEMENT.	10-B-41	
10-B-42	ENERGY BANKING AGREEMENT DATED MARCH 21, 1983, ... AMONG HYDRO-QUEBEC, VELCO, NEET AND PARTI-CIPATING NEW ENGLAND UTILITIES ACTING BY AND THROUGH THE NEPOOL MANAGEMENT COMMITTEE FOR TERMS OF ENERGY BANKING BETWEEN PARTICIPATING NEW ENGLAND UTILITIES AND HYDRO-QUEBEC.	10-B-42	
10-B-43	INTERCONNECTION AGREEMENT DATED MARCH 21, 1983,. . . . . BETWEEN HYDRO-QUBEC AND PARTICIPATING NEW ENGLAND UTILITIES ACTING BY AND THROUGH THE NEPOOL MANAGEMENT COMMITTEE FOR TERMS AND CONDITIONS OF ENERGY TRANSMISSION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC.	10-B-43	
10-B-44	ENERGY CONTRACT DATED MARCH 21, 1983, BETWEEN. . . . . HYDRO-QUEBEC AND PARTICIPATING NEW ENGLAND UTILITIES ACTING BY AND THROUGH THE NEPOOL MANAGEMENT COMMITTEE FOR PURCHASE OF SURPLUS ENERGY FROM HYDRO-QUEBEC.	10-B-44	
10-B-50	AGREEMENT FOR JOINT OWNERSHIP, CONSTRUCTION AND. . . . . OPERATION OF THE HIGHGATE TRANSMISSION INTERCONNECTION, DATED AUGUST 1, 1984, BETWEEN CERTAIN ELECTRIC DISTRIBUTION COMPANIES, INCLUDING THE COMPANY.	10-B-50	
10-B-51	HIGHGATE OPERATING AND MANAGEMENT AGREEMENT, ... DATED AS OF AUGUST 1, 1984, AMONG VELCO AND VERMONT ELECTRIC-UTILITY COMPANIES, INCLUDING THE COMPANY.	10-B-51	
10-B-52	ALLOCATION CONTRACT FOR HYDRO-QUEBEC FIRM POWER. . . . . DATED JULY 25, 1984, BETWEEN THE STATE OF VERMONT AND VARIOUS VERMONT ELECTRIC UTILITIES, INCLUDING THE COMPANY.	10-B-52	
10-B-53	HIGHGATE TRANSMISSION AGREEMENT DATED AS OF. . . . . AUGUST 1, 1984, BETWEEN THE OWNERS OF THE PROJECT AND VARIOUS VERMONT ELECTRIC DISTRIBUTION COMPANIES.	10-B-53	
10-B-61	AGREEMENTS ENTERED IN CONNECTION WITH PHASE II . . . . OF THE NEPOOL/HYDRO-QUEBEC + 450 KV HVDC TRANSMISSION INTERCONNECTION.	10-B-61	
10-B-62	AGREEMENT BETWEEN UNITIL POWER CORP. AND THE . . . . COMPANY TO SELL 23 MW CAPACITY AND ENERGY FROM STONY BROOK INTERMEDIATE COMBINED CYCLE UNIT.	10-B-62	
10-B-68	FIRM POWER AND ENERGY CONTRACT DATED DECEMBER 4, ... 1987, BETWEEN HYDRO-QUEBEC AND PARTICIPATING VERMONT UTILITIES, INCLUDING THE COMPANY, FOR THE PURCHASE OF FIRM POWER FOR UP TO THIRTY YEARS.	10-B-68	FORM 10-K
10-B-69	FIRM POWER AGREEMENT DATED AS OF OCTOBER 26, 1987, ... BETWEEN ONTARIO HYDRO AND VERMONT DEPARTMENT OF PUBLIC SERVICE.	10-B-69	FORM 10-K
10-B-70	FIRM POWER AND ENERGY CONTRACT DATED AS OF	10-B-70	FORM 10-K

	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-70(A)	FORM 10-K
10-B-71	INTERCONNECTION AGREEMENT DATED AS OF. . . . . FEBRUARY 23, 1987, BETWEEN THE VERMONT JOINT OWNERS OF THE HIGHGATE FACILITIES AND HYDRO-QUEBEC.	10-B-71	FORM 10-K
10-B-72	PARTICIPATION AGREEMENT DATED AS OF APRIL 1, 1988, ... BETWEEN HYDRO-QUEBEC AND PARTICIPATING VERMONT UTILITIES, INCLUDING THE COMPANY, IMPLEMENTING THE PURCHASE OF FIRM POWER FOR UP TO 30 YEARS UNDER THE FIRM POWER AND ENERGY CONTRACT DATED DECEMBER 4, 1987 (PREVIOUSLY FILED WITH THE COMPANY'S ANNUAL REPORT ON FORM 10-K FOR 1987, EXHIBIT NUMBER 10-B-68).	10-B-72	FORM 10-Q JUNE 1988
10-B-72(A)	RESTATEMENT OF THE PARTICIPATION AGREEMENT FILED . . . . AS EXHIBIT 10-B-72 ON FORM 10-Q FOR JUNE 1988.	10-B-72(A)	FORM 10-K
10-B-77	FIRM POWER AND ENERGY CONTRACT DATED DECEMBER 29,. . . . . 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-77	FORM 10-K
10-B-78	TRANSMISSION AGREEMENT DATED DECEMBER 23, 1988,. . . . . BETWEEN THE COMPANY AND NIAGARA MOHAWK POWER CORPORATION (NIAGARA MOHAWK), FOR NIAGARA MOHAWK TO PROVIDE ELECTRIC TRANSMISSION TO THE COMPANY FROM ROCHESTER GAS AND ELECTRIC AND CENTRAL HUDSON GAS AND ELECTRIC.	10-B-78	FORM 10-K
10-B-81	SALES AGREEMENT DATED MAY 24, 1989, BETWEEN. . . . . THE TOWN OF HARDWICK, HARDWICK ELECTRIC DEPARTMENT AND THE COMPANY FOR THE COMPANY TO PURCHASE ALL OF THE OUTPUT OF HARDWICK'S GENERATION AND TRANSMISSION SOURCES AND TO PROVIDE HARDWICK WITH ALL-REQUIREMENTS ENERGY AND CAPACITY EXCEPT FOR THAT PROVIDED BY THE VERMONT DEPARTMENT OF PUBLIC SERVICE OR FEDERAL PREFERENCE POWER.	10-B-81	FORM 10-Q JUNE 1989
10-B-82	SALES AGREEMENT DATED JULY 14, 1989, BETWEEN . . . . NORTHFIELD ELECTRIC DEPARTMENT AND THE COMPANY FOR THE COMPANY TO PURCHASE ALL OF THE OUTPUT OF NORTHFIELD'S GENERATION AND TRANSMISSION SOURCES AND TO PROVIDE NORTHFIELD WITH ALL-REQUIREMENTS ENERGY AND CAPACITY EXCEPT FOR THAT PROVIDED BY THE VERMONT DEPARTMENT OF PUBLIC SERVICE OR FEDERAL PREFERENCE POWER.	10-B-82	FORM 10-Q JUNE 1989
10-B-85	POWER PURCHASE AND SALE AGREEMENT BETWEEN. . . . . MORGAN STANLEY CAPITAL GROUP INC. AND THE COMPANY	10-B-85	FORM 10-K
10-B-86	REVOLVING CREDIT AGREEMENT WITH KEYBANK.	10-B-86	FORM 10-Q
10-B-87	AMENDMENT TO FLEET REVOLVING CREDIT AGREEMENT.	10-B-87	FORM 10-Q
10-B-88	ENERGY EAST POWER PURCHASE OPTION AGREEMENT.	10-B-88	FORM 10-Q
10-B-89	SECOND AMENDED AND RESTATED CREDIT AGREEMENT BETWEEN . . . . . . KEYBANK NATIONAL ASSOCIATION, FLEET NATIONAL BANK, AND THE COMPANY DATED JUNE 20, 2001	10-B-89	FORM 10-K
10-B-90	PURCHASE POWER AGREEMENT BETWEEN ENTERGY NUCLEAR VERMONT . . . YANKEE LLC AND VERMONT YANKEE NUCLEAR POWER CORPORATION	10-B-90	FORM 10-Q
10-B-91	FIRST AMENDMENT TO PURCHASE POWER AGREEMENT LISTED AS. . . . . . EXHIBIT NUMBER 10-B-90, BETWEEN ENTERGY NUCLEAR VERMONT YANKEE LLC AND VERMONT YANKEE NUCLEAR POWER CORPORATION	10-B-90	FORM 10-Q
10-B-92	AMENDMENT TO POWER PURCHASE AND SALE AGREEMENT	10-B-92	FORM 10-K

BETWEEN MORGAN STANLEY CAPITAL GROUP, INC. AND THE COMPANY

MANAGEMENT CONTRACTS OR COMPENSATORY PLANS OR ARRANGEMENTS REQUIRED TO BE FILED AS EXHIBITS TO THIS FORM 10-K

PURSUANT TO ITEM 14(C)., ALL UNDER SEC DOCKET 1-8291

10-D-1B.	GREEN MOUNTAIN POWER CORPORATION SECOND AMENDED AND RESTATED DEFERRED COMPENSATION PLAN FOR DIRECTORS.	10-D-1B	FORM 10-K 1993
10-D-1C.	GREEN MOUNTAIN POWER CORPORATION SECOND AMENDED AND RESTATED DEFERRED COMPENSATION PLAN FOR OFFICERS.	10-D-1C	FORM 10-K 1993
10-D-1D.	AMENDMENT NO. 93-1 TO THE AMENDED AND RESTATED DEFERRED COMPENSATION PLAN FOR OFFICERS.	10-D-1D	FORM 10-K 1993
10-D-1E.	AMENDMENT NO. 94-1 TO THE AMENDED AND RESTATED DEFERRED COMPENSATION PLAN FOR OFFICERS.	10-D-1E	FORM 10-Q JUNE 1994
10-D-2 .	GREEN MOUNTAIN POWER CORPORATION MEDICAL EXPENSE REIMBURSEMENT PLAN.	10-D-2	FORM 10-K 1991
10-D-4 .	GREEN MOUNTAIN POWER CORPORATION OFFICER INSURANCE PLAN.	10-D-4	FORM 10-K 1991
10-D-4A.	GREEN MOUNTAIN POWER CORPORATION OFFICERS' INSURANCE PLAN AS AMENDED.	10-D-4A	FORM 10-K 1990
10-D-8 .	GREEN MOUNTAIN POWER CORPORATION OFFICERS' SUPPLEMENTAL RETIREMENT PLAN.	10-D-8	FORM 10-K 1990
10-D-15B	GREEN MOUNTAIN POWER CORPORATION COMPENSATION PROGRAM FOR OFFICERS AND KEY MANAGEMENT PERSONNEL AS AMENDED AUGUST 4, 1997	10-D-15B	FORM 10-K 1997
10-D-15C	GREEN MOUNTAIN POWER 2000 STOCK INCENTIVE PLAN	10-D-15C	FORM 10-K 2001
10-D-40.	SEVERANCE AGREEMENT WITH C. L. DUTTON	10-D-40	FORM 10-K 2003
10-D-41.	SEVERANCE AGREEMENT WITH D.J. RENDALL	10-D-41	FORM 10-K 2003
10-D-42.	SEVERANCE AGREEMENT WITH R. J. GRIFFIN	10-D-42	FORM 10-K 2003
10-D-43.	SEVERANCE AGREEMENT WITH W. S. OAKES	10-D-43	FORM 10-K 2003
10-D-44.	SEVERANCE AGREEMENT WITH M. G. POWELL	10-D-44	FORM 10-K 2003
10-D-45.	SEVERANCE AGREEMENT WITH S. C. TERRY	10-D-45	FORM 10-K 2003
10-D-46.	DEFERRED STOCK UNIT AGREEMENT WITH D.J. RENDALL	10-D-46	FORM 10-K 2003
10-D-47.	DEFERRED STOCK UNIT AGREEMENT WITH C. L. DUTTON	10-D-47	FORM 10-K 2003
10-D-48.	DEFERRED STOCK UNIT AGREEMENT WITH S. C. TERRY	10-D-48	FORM 10-K 2003
10-D-49.	DEFERRED STOCK UNIT AGREEMENT WITH R. J. GRIFFIN	10-D-49	FORM 10-K 2003
10-D-50.	DEFERRED STOCK UNIT AGREEMENT WITH W. S. OAKES	10-D-50	FORM 10-K 2003
10-D-51.	DEFERRED STOCK UNIT AGREEMENT WITH M. G. POWELL	10-D-51	FORM 10-K 2003
10-D-52.	DEFERRED STOCK UNIT AGREEMENT WITH E. A. BANKOWSKI	10-D-52	FORM 10-K 2004
10-D-53.	DEFERRED STOCK UNIT AGREEMENT WITH N. L. BRUE	10-D-53	FORM 10-K 2003
10-D-54.	DEFERRED STOCK UNIT AGREEMENT WITH W. H. BRUETT	10-D-54	FORM 10-K 2003
10-D-55.	DEFERRED STOCK UNIT AGREEMENT WITH M. O. BURNS	10-D-55	FORM 10-K 2003
10-D-56.	DEFERRED STOCK UNIT AGREEMENT WITH L. E. CHICKERING	10-D-56	FORM 10-K 2003
10-D-57.	DEFERRED STOCK UNIT AGREEMENT WITH J. V. CLEARY	10-D-57	FORM 10-K 2003
10-D-58.	DEFERRED STOCK UNIT AGREEMENT WITH D.R. COATES	10-D-58	FORM 10-K 2003
10-D-59.	DEFERRED STOCK UNIT AGREEMENT WITH E. A. IRVING	10-D-59	FORM 10-K 2003
10-D-60.	DIRECTOR DEFERRAL AGREEMENT WITH E. A. BANKOWSKI	10-D-60	FORM 10-K 2003
10-D-61.	DIRECTOR DEFERRAL AGREEMENT WITH M. O. BURNS	10-D-61	FORM 10-K 2003
10-D-62.	DIRECTOR DEFERRAL AGREEMENT WITH D. R. COATES	10-D-62	FORM 10-K 2003
10-D-63.	DIRECTOR DEFERRAL AGREEMENT WITH E. A. IRVING	10-D-63	FORM 10-K 2003
*23-A-1.	CONSENT OF ARTHUR ANDERSEN LLP	23-A-1	
23-A-2 .	CONSENT OF DELOITTE AND TOUCHE LLP	23-A-2	
24 . . .	LIMITED POWER OF ATTORNEY	24	

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, 2003, and generally to do all such things in our name and behalf in our capacities as directors to enable Green Mountain Power Corporation to comply with the provisions of the Securities Exchange Act of 1934, as amended, all requirements of the Securities and Exchange Commission, and all requirements of any other applicable law or regulation, hereby ratifying and confirming our signatures as they may be signed by our said attorney, to said Annual Report.

SIGNATURE	TITLE	DATE
/s/Christopher L. Dutton Christopher L. Dutton	President and Director (Principal Executive Officer)	February 25, 2004
/s/Nordahl L. Brue Nordahl L. Brue	Chairman of the Board	March 4, 2004
/s/Elizabeth A. Bankowski Elizabeth A. Bankowski	Director	March 1, 2004
/s/William H. Bruett William H. Bruett	Director	March 3, 2004
/s/Merrill O. Burns Merrill O. Burns	Director	March 1, 2004
/s/Lorraine E. Chickering Lorraine E. Chickering	Director	March 2, 2004
/s/John V. Cleary John V. Cleary	Director	March 4, 2004
/s/David R. Coates David R. Coates	Director	March 4, 2004
/s/Euclid A. Irving		March 1, 2004

Euclid A. Irving	Director

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: February 25, 2004

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	February 25, 2004
/s/ Mary G. Powell_______ Mary G. Powell	Chief Operating Officer, Senior Vice President	March 10, 2004
/s/ Robert J. Griffin Robert J. Griffin	Chief Financial Officer, Vice President and Treasurer	February 25, 2004
*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 February 25, 2004

Christopher L. Dutton
(Attorney - in - Fact)