GREEN MOUNTAIN POWER CORP
Form 10-K
March 29, 2005

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, 2004
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 JUNE 30, 2004, WAS APPROXIMATELY $132,535,487 BASED ON THE CLOSING PRICE OF $26.10 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 17, 2005, WAS 5,164,205.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 23, 2005, to be filed with the Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference in Items 10, 11, 12 and 13 of Part III of this Form 10-K.

Green Mountain Power Corporation
Form 10-K for the fiscal year ended December 31, 2004

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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 2004 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 that transmits, distributes and sells electricity and utility construction services in the State of Vermont ("State" or "Vermont") in a service territory with approximately one quarter of Vermont's population. We serve approximately 90,000 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, 2004 were as follows:

* 33.4 percent from residential customers;
* 33.2 percent from small commercial and industrial customers;
* 21.7 percent from large commercial and industrial customers;
* 9.9 percent from sales to other utilities; and
* 1.8 percent from other sources.

Approximately 98 percent of our revenue has resulted from the sale of electricity over the period 2002 - 2004.

See the Company's Annual Report and MD and A, Item 7 below, for further information about revenues.

During 2004, our energy resources for retail sales of electricity were obtained as follows:

* 37.5 percent from hydroelectric sources (29.2 percent Hydro Quebec, 4.9 percent Company-owned, and 3.4 percent independent power producers);
* 36.9 percent from a nuclear generating source (the Entergy Nuclear Vermont Yankee, LLC ("ENVY") nuclear plant described below);
* 3.9 percent from wood;
* 2.5 percent from natural gas or oil; and
* 0.5 percent from wind.

The remaining 18.7 percent was purchased on a short-term basis from generators through the wholesale market operated by ISO New England, Inc. formerly the New England Power Pool ("NEPOOL").

In 2004, we estimate that we purchased under existing contracts or generated approximately 90 percent of our energy resources to satisfy our retail and wholesale sales of electricity under long-term arrangements, including our contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") described below. Remaining retail and wholesale sales were met through short-term market purchases and represent primarily 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 Entergy Vermont Yankee Nuclear LLC ("ENVY") (the "Vermont Yankee" or "VY" plant). We have a 33.6 percent equity interest in Vermont Yankee Nuclear Power Corporation ("VYNPC"), which has a long-term power supply contract with ENVY that entitles us to 20 percent of Vermont Yankee plant output through 2012. For further information concerning Vermont Yankee, see Power Resources - Vermont Yankee, below.

The Company owns approximately 29.2 percent of common stock and 30.0 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"). VELCO owns the high-voltage transmission system in Vermont. VELCO's wholly-owned subsidiary, Vermont Electric Transmission Company, Inc. ("VETCO"), was formed to finance, construct and operate the Vermont portion of the 450 kV DC transmission line connecting the Province of Quebec with Vermont and New England. For further information concerning VELCO, see VELCO below.

The Company participates in the New England regional wholesale electric power markets operated by ISO New England, Inc. ("ISO-NE") the regional bulk power transmission organization established to assure reliable and economical power supply in New England. The Federal Energy Regulatory Commission ("FERC") has granted approval to ISO-NE to become a regional transmission organization ("RTO") for New England. On February 1, 2005, ISO-NE commenced operations as the RTO, providing regional transmission service in New England, with operational control of the bulk power system and responsibility for administering wholesale markets. 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 agreement 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 VELCO and others. Included in these areas are the communities of Vernon (where the Vermont Yankee 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 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,			
	2004	2003	2002	2001

Net system peak (MW*)	326.7	330.2	342.0	34
Production and purchases (MWH**)				
Hydro	777,292	838,855	901,998	951,
Wind	11,023	10,828	11,458	12,
Nuclear	764,010	884,585	771,781	736,
Conventional steam	89,622	100,402	85,910	33,
Internal combustion	13,026	12,603	4,090	18,
Combined cycle	32,224	68,488	81,362	72,
Bilateral and system purchases	793,939	2,423,831	2,345,205	2,637,
Total production	2,481,136	4,339,592	4,201,804	4,460,
Less non-firm sales to other utilities	408,601	2,284,003	2,104,172	2,365,
Production for firm sales	2,072,535	2,055,589	2,097,632	2,095,
Less firm sales and lease transmissions	1,973,093	1,937,376	1,951,959	1,956,
Losses and company use (MWH)	99,442	118,213	145,673	138,
Losses as a % of total production	4.01%	2.72%	3.47%	3
System load factor (***)	72.4%	71.1%	70.0%	7
Net Production (% of Total)				
Hydro	31.3%	19.3%	21.5%	2
Wind	0.4%	0.2%	0.3%	
Nuclear	30.8%	20.4%	18.3%	1
Conventional steam	3.6%	2.3%	2.0%	
Internal combustion	0.5%	0.3%	0.1%	
Combined cycle	1.3%	1.6%	1.9%	
Bilateral and system purchases	32.1%	55.9%	55.8%	5
Total	100.0%	100.0%	100.0%	10
Sales and Lease Transmissions(MWH)				
Residential - GMPC	580,710	581,047	553,294	549,
Commercial & industrial - small	715,602	703,036	695,504	691,
Commercial & industrial - large	666,503	645,271	689,618	710,
Other	7,112	4,986	9,773	2,
Total retail sales and lease transmissions	1,969,927	1,934,340	1,948,189	1,953,
Sales to Municipals & Cooperatives (Rate W)	3,166	3,036	3,770	3,
Total Requirements Sales	1,973,093	1,937,376	1,951,959	1,956,
Other Sales for Resale	408,601	2,284,003	2,104,172	2,365,
Total sales and lease transmissions(MWH)	2,381,694	4,221,379	4,056,131	4,322,
Average Number of Electric Customers				
Residential	75,507	74,693	73,861	73,
Commercial and industrial small	13,515	13,344	13,165	12,
Commercial and industrial large	24	25	29	
Other	62	65	65	
Total	89,108	88,127	87,120	86,
Average Revenue Per KWH (Cents)				
Residential including lease revenues	13.15	12.98	12.96	13
Commercial & industrial - small	10.63	10.40	10.44	10
Commercial & industrial - large	7.44	7.41	7.31	7
Total retail	10.32	10.22	10.09	10

Average Use and Revenue Per Residential Customer				
KWh's including lease transmissions	7,691	7,779	7,491	7,
Revenues including lease revenues	$ 1,012	$ 1,010	$ 971	$

(*) 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 ("DPS" or the "Department"), created by statute in 1981, acts as the public advocate in rate and other state regulatory proceedings and 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.

Certain components of the businesses of the Company and VELCO, including certain rates, are subject to the jurisdiction of the FERC as follows: the Company as a licensee of hydroelectric developments under Part I of the Federal Power Act, and the Company and VELCO as interstate public utilities under Parts II and III of the Federal Power Act, as amended and supplemented by the National Energy Act.

Our transmission assets and the wholesale rate on sales to two wholesale customers are regulated by the FERC. Revenues from sales to these customers were less than 1.0 percent of our operating revenues for 2004.

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 2004.

On July 17, 1997, the FERC approved our Open Access Transmission Tariff. On November 26, 2004, we received from FERC an exemption from the standards of conduct requirements of FERC Order 2004, governing separation of transmission operations. 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 VYNPC, VELCO and VETCO. 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 . .	July 30, 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 2005. When repairs and re-licensing proceedings 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. On January 19, 2005, the Department adopted a new 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.

On 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. The Company filed a cost of service schedule pursuant to the plan in November 2004 and received approval from the VPSB to implement the plan's 2005 1.9 percent rate increase, effective January 1, 2005.

Allows the Company the opportunity to file for rate increases during the period from January 1, 2003 to December 31, 2006 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.

For further discussion of the Company's 2003 Rate Plan, see Item 7a. Quantitative and Qualitative Disclosures About Market Risk, and Other Risk

Factors - Rates.

SINGLE CUSTOMER DEPENDENCE

The Company had one major retail customer, IBM, metered at two locations that accounted for 16.4 percent, 16.6 percent and 17.3 percent of the Company's retail operating revenues in 2004, 2003 and 2002, 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 approximately five percent, inclusive of projected declines in sales to other residential and commercial customers. See Item 7a. Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors - Customer Concentration Risk, and Note A of Notes.

COMPETITION AND RESTRUCTURING

Competition currently takes several forms. At the wholesale level New England has implemented its version of FERC's "standard market design ("SMD"), which is a detailed competitive market framework that has resulted in bid-based competition of power suppliers rather than prices set under cost of service regulation. At the retail level, customers have long had energy options such as propane, natural gas or oil for heating, cooling and water heating, and self-generation. Another competitive threat is the potential for customers to form municipally owned utilities in the Company's service territory.

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. 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 $56 million and $96 million over the life of the Company's current contracts.

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. There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont. For further information regarding Competition and Restructuring, See Item 7a. Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors - Regulatory Risk.

The Town of Rockingham, Vermont, located in the southeastern portion of our service territory, has exercised an option to purchase a hydro-electric facility partially located in the town (the "Bellows Falls facility"). If Rockingham or its assignee is successful in arranging for purchase of the Bellows Falls facility, we expect to conclude an agreement to permit Rockingham to be responsible for its own power supply needs, with the Company providing distribution and other services to the town. In any such agreement the Company would continue to own its distribution plant located in the town and receive distribution services revenues sufficient to cover all costs of providing services and all stranded costs associated with the Company's present obligation to provide integrated electric service to customers in Rockingham. Such an arrangement would require VPSB approval. The Company receives annual revenues of approximately $3 million from its customers in Rockingham.

CONSTRUCTION AND CAPITAL REQUIREMENTS

Our capital expenditures for 2002 through 2004 and projected for 2005 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

We generated, purchased or transmitted 2,072,535 MWh of energy for retail and requirements wholesale customers for the twelve months ended December 31, 2004. The corresponding maximum one-hour integrated demand during that period was 326.7 MW on December 21, 2004. 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 12/31/2004		Capacity At time of of annual peak	
	MWH	percent	KW	percent
Wholly-owned plants:				
Hydro	101,517	4.9%	23,370	6.3%
Diesel and Gas Turbine.	13,026	0.6%	58,550	15.8%
Wind.	11,023	0.5%	960	0.3%
Jointly-owned plants:				
Wyman #4.	5,830	0.3%	6,470	1.7%
Stony Brook I	22,117	1.1%	30,936	8.3%
McNeil.	24,171	1.2%	5,770	1.6%
Long Term Purchases:				
Vermont Yankee/ENVY	764,010	36.9%	97,451	26.3%
Hydro Quebec.	605,718	29.2%	107,391	29.0%
Stony Brook I	10,107	0.5%	14,124	3.8%
Other:				
Independent Power Producers . .	124,617	6.0%	25,610	6.9%

Morgan Stanley.	193,158	9.3%	-	-
ISO-NE and Short-term purchases	197,241	9.5%	-	-
Net Own Load.	2,072,535	100.0%	370,632	100.0%

VERMONT YANKEE.

On July 31, 2002, VYNPC 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 VYNPC, 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 VYNPC 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 Vermont Yankee plant.

Our ownership share of VYNPC increased from approximately 19.0 percent in 2003 to approximately 33.6 percent currently, due to VYNPC's purchase last year of certain minority shareholders' interests. VYNPC's primary role consists of administering its power supply contract with ENVY and its contracts with VYNPC's present sponsors. Our entitlement to energy produced by the Vermont Yankee nuclear plant has remained at 20 percent of plant production.

During periods when Vermont Yankee power is unavailable, the costs of replacement power occasionally exceed those costs that we would have incurred for power purchased pursuant to our power supply agreement with VYNPC. Replacement power is available to us from the wholesale market 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.

Vermont Yankee's current operating license expires March 2012. Since the Company no longer owns an interest in the Vermont Yankee nuclear plant, we no longer bear the operating costs and risks associated with running and decommissioning the plant.

During the year ended December 31, 2004, we used 764,010 MWh of Vermont Yankee energy (supplied by ENVY) representing 36.9 percent of the net electricity generated and purchased ("net power supply") by the Company.

See Item 7a. Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors - Other Power Supply Risks, and Notes B and 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. Commencing with implementation of New England's RTO, the Highgate facilities are now controlled and operated by

ISO-NE. We do not expect ISO-NE's operation or control of these facilities to affect the Company's deliveries of power from Hydro Quebec under our current power contract commitments.

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 National Grid, successor to New England Electric System.

Phase II. Phase II provides 2,000 MW of capacity for transmission of Hydro Quebec power 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, 2004, the present value of the Company's obligation was approximately $4.2 million. The Company's projected future minimum payments under the Phase II support agreements are approximately $383,000 for each of the years 2005-2009 and an aggregate of $2,299,000 for the years 2010-2015.

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 National Grid, successor to New England Electric System, in which certain of the Phase II participating utilities, including the Company, own equity interests. The Company owns approximately 3.2 percent of the equity of the corporations owning the Phase II facilities. See Note B and Note J of Notes.

Hydro Quebec Power Supply Contracts. The bulk of our purchases from Hydro Quebec are pursuant to two schedules, B and C3, of 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 agreement (the "9701 agreement") with Hydro Quebec under which Hydro Quebec paid $8,000,000 to the Company in exchange for certain power purchase options. See Item 7a. Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors - Power Contract Commitments, and Note K of Notes.

During 2004, we used 363,849 MWh under Schedule B, and 241,869 MWh under Schedule C3 of the VJO Contract, representing 29.2 percent of our net power supply.

MORGAN STANLEY CONTRACT - 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 7a. Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors - Power Contract Commitments and Note K of Notes.

ISO-NE 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 to recover all of the forecasted fuel or production costs and to recover some, if not all, associated capacity costs. During 2004, the Company purchased 197,241 MWh representing 9.5 percent of the Company's net power supply.

During 2002, the FERC accepted ISO-NE's request to implement a Standard Market Design ("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. 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 2004, we used 32,224 MWh from this plant representing 1.6 percent of our net power supply. 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. Florida Power & Light is the principal owner and operator of the 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 2004, we used 5,830 MWh from this unit representing 0.3 percent of our net power supply. 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 2004, we used 24,171 MWh from this unit representing 1.2 percent of our net power supply. See Note I of Notes. The Burlington Electric Department is the principal owner and operator of the McNeil plant.

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 2004 was approximately 34.3 percent or 51.5 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 currently under development.

In 2004, through our direct contracts and VEPPI, we purchased 124,617 MWh of qualifying facilities production representing 6.0 percent of our net power supply.

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 2004, Company owned hydroelectric plants produced 101,517 MWh, representing 4.9 percent of our net power supply. See State and Federal Regulation - Licensing.

VELCO. The Company and fifteen 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 matters. See Note B of Notes.

FUEL. During 2004, our retail and requirements wholesale sales were provided by the following fuel sources:

* 37.5 percent from hydroelectric sources (29.2 percent Hydro Quebec, 4.9 percent Company-owned, and 3.4 percent independent power producers;
* 36.9 percent from a nuclear generating source (the Vermont Yankee nuclear plant);
* 3.9 percent from wood;
* 2.5 percent from natural gas and oil;
* 0.5 percent from wind; and
* 18.7 percent purchased on a short-term basis from other utilities through the ISO-NE and Morgan Stanley.

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 2004. None of the utilities from which we expect to purchase oil- or gas-fired capacity in 2005 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 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.

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 2004, the project produced 11,023 MWh, representing 0.5 percent of the Company's net power supply.

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 A 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, 2004, the Company had 192 employees, exclusive of temporary employees. The Company considers its relations with employees to be excellent. The current labor contract expires December 31, 2007.

ENERGY EFFICIENCY

In 2004, 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 1,715 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 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, 2004, approximately 1,587 of the Company's largest customers, comprising approximately 51 percent of retail revenues, received service on mandatory time-of-use rates. Pursuant to the Company's 2003 Rate Plan, in March 2004, the Company filed with the VPSB a new fully-allocated cost of service study and rate re-design, which re-allocates the Company's revenue requirement among all customer classes on the basis of current costs. The Company's new proposed rate design is subject to VPSB approval. We do not expect the proposed rate design to adversely affect operating results.

DISPATCHABLE AND INTERRUPTIBLE SERVICE CONTRACTS

In 2004, we had 26 dispatchable power contracts: 22 contracts were year-round, and 4 customers had seasonal contracts. 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

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 non-performing note from a hydroelectric facility in New Hampshire, and a wastewater business in the process of completing dissolution. For information regarding our unregulated businesses, see Note A of the Notes.

EXECUTIVE OFFICERS

The names, ages, and positions of our Executive Officers, in alphabetical order, as of March 15, 2005 are:

Christopher L. Dutton 56

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 48

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 58

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 44

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 49

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 62

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 April 12, 2005, 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. We also make available on the website the Company's Corporate Governance Guidelines, Code of Ethics and Conduct, Bylaws, and the Charters of the Audit, Compensation and Governance Committees of the Company. 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 35.3 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 58.5 MW. We have two diesel generating stations with an aggregate nameplate rating of 8.0 MW and an estimated aggregate claimed capability of 6.3 MW. We also have a wind generating facility with a nameplate rating of 6.1 MW and a claimed capability of 5.9 MW.

We also own:

* 33.6 percent of the outstanding common stock of Vermont Yankee Nuclear Power Corporation 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 Vermont Yankee 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, 2004, approximately 2 miles of 115 kV transmission lines, 10 miles of 69 kV transmission lines, 5 miles of 44 kV transmission lines, 196 miles of 34.5 kV transmission lines, and 2 miles of 13.8 kV transmission lines. Our distribution system included approximately 2,657 miles of overhead lines of 2.4 to 34.5 kV and 433 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 949,000 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. The Company also owns 59.4 percent of the metallic neutral return, a neutral conductor for the NEPOOL/Hydro Quebec interconnection.

We also own 29.2 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.

VELCO's properties consist of about 573 miles of high voltage overhead transmission lines and associated substations. The lines connect on the west with the lines of Niagara Mohawk Power Corporation at the Vermont-New York state line near Whitehall, New York, and Bennington, Vermont, and with the submarine cable of NYPA near Plattsburgh, New York; on the south and east with the lines of New England Power Company and PSNH; on the south with the facilities of

Vermont Yankee; and on the north with lines of Hydro Quebec through a converter station and tie line jointly owned by the Company and several other Vermont utilities.

VELCO's wholly-owned subsidiary, VETCO, has about 52 miles of high voltage DC transmission line connecting with the transmission line of Hydro Quebec at the Quebec-Vermont border in the Town of Norton, Vermont; and connecting with the transmission line of New England Electric Transmission Corporation, a subsidiary of National Grid USA, at the Vermont-New Hampshire border near New England Power Company's Moore hydro-electric generating station.

PROPERTY OWNERSHIP

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

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

INDENTURE OF FIRST MORTGAGE

The Company's interests in substantially all of its properties and franchises are subject to the lien of the mortgage securing its First Mortgage Bonds. See Note F, Long-Term Debt, for more information concerning our First Mortgage Bonds.

GENERATING FACILITIES OWNED

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

	Location	Name	Fuel	Winter claimed capability MW
Wholly Owned				
Hydro	Middlesex, VT	Middlesex #2	Hydro	3.3
Hydro	Marshfield, VT	Marshfield #6	Hydro	4.9
Hydro	Vergennes, VT	Vergennes #9	Hydro	2.1
Hydro	W. Danville, VT	W. Danville #15	Hydro	1.1
Hydro	Colchester, VT	Gorge #18	Hydro	3.3
Hydro	Essex Jct., VT	Essex #19	Hydro	7.8
Hydro	Waterbury, VT	Waterbury #22 (1)	Hydro	5.0
Hydro	Bolton, VT	DeForge #1	Hydro	7.8
Diesel.	Vergennes, VT	Vergennes #9	Oil	4.1
Diesel.	Essex Jct., VT	Essex #19	Oil	2.2
Gas Turbine	Berlin, VT	Berlin #5	Oil	45.0
Turbine	Colchester, VT	Gorge #16	Oil	13.5
Wind.	Searsburg, VT	Searsburg	Wind	5.9
Jointly Owned				
Steam	Yarmouth, ME	Wyman #4	Oil	6.9
Steam	Burlington, VT	McNeil (2)	Wood/Gas	6.6
Combined.	Ludlow, MA	Stony Brook #1	Oil/Gas	31.0
Total Winter Capability				150.5

(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 2004 and 2003:

	HIGH	LOW
	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
	2004	
First Quarter.	$26.29	$22.60
Second Quarter	26.10	24.40
Third Quarter.	26.82	25.08
Fourth Quarter	29.15	24.80

The number of common stockholders of record as of February 18, 2004 was approximately 5,119, $3.33333 par value.

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2003	$ 0.19	$ 0.19	$ 0.19	$ 0.19
2004	$ 0.22	$ 0.22	$ 0.22	$ 0.22

Dividend Policy. The Company increased its dividend in February 2005 from an annual rate of $0.88 per share to $1.00 per share. The Company's dividend payout ratio remains comparatively low, at approximately 48 percent of 2004 earnings from continuing operations. We expect to grow our dividend payout ratio to the middle of a payout range of 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.

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.

ITEM 6. SELECTED FINANCIAL DATA

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31,

	2004	2003	2002
In thousands, except per share data			
Operating Revenues	$228,816	$280,470	$274,608
Operating Expenses	213,338	265,164	259,528
Operating Income	15,478	15,306	15,080
Other Income			
AFUDC - equity	449	387	233
Other	1,638	1,692	2,252
Total other income	2,087	2,079	2,485
Interest Charges			
AFUDC - borrowed	(285)	(267)	(103)
Other	6,791	7,324	6,273
Total interest charges	6,506	7,057	6,170
Net Income (Loss) from continuing operations before preferred dividends	11,059	10,328	11,395
Net Income (Loss) from discontinued operations, including provisions for loss on disposal	525	79	99
Dividends on Preferred Stock	-	3	96
Net Income (Loss)Applicable to Common Stock	$ 11,584	$ 10,404	$ 11,398
Common Stock Data			
Basic earnings per share-continuing operations	$ 2.18	$ 2.08	$ 2.02
Basic earnings per share-discontinued operations	$ 0.10	$ 0.01	$ 0.02
Basic earnings per share	$ 2.28	$ 2.09	$ 2.04
Diluted earnings (loss) per share from continuing operations	$ 2.10	$ 2.01	$ 1.96
Diluted earnings (loss) per share from discontinued operations	$ 0.10	$ 0.01	$ 0.02
Diluted earnings (loss) per share	$ 2.20	$ 2.02	$ 1.98
Cash dividends declared per share	$ 0.88	$ 0.76	$ 0.60
Weighted average shares outstanding-basic	5,083	4,980	5,592
Weighted average equivalent shares outstanding-diluted	5,254	5,140	5,756

FINANCIAL CONDITION AS OF DECEMBER 31

	2004	2003	2002	2001	2000
In thousands					

ASSETS					
Utility Plant, Net.	$232,712	$228,862	$223,476	$196,858	$194,672
Other Investments	18,959	13,706	21,552	20,945	20,730
Current Assets.	35,462	31,688	31,432	36,183	53,652
Deferred Charges.	53,731	55,590	60,390	72,468	46,036
Non-Utility Assets.	755	1,105	995	1,075	1,518
Total Assets.	$341,619	$330,951	$337,845	$327,529	$316,608
	========	========	========	========	========
CAPITALIZATION AND LIABILITIES					
Common Stock Equity	$109,581	$ 99,915	$ 91,722	$101,277	$ 92,044
Redeemable Cumulative Preferred Stock .	-	-	55	12,560	12,795
Long-Term Debt, Less Current Maturities	93,000	93,000	93,000	74,400	72,100
Capital Lease Obligation.	4,493	4,963	5,287	5,959	6,449
Current Liabilities	24,468	22,715	38,491	38,841	68,109
Deferred Credits and Other.	107,906	108,281	107,349	92,791	61,794
Non-Utility Liabilities	2,171	2,077	1,941	1,701	3,317
Total Capitalization and Liabilities. .	$341,619	$330,951	$337,845	$327,529	$316,608
	========	========	========	========	========

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD AND A").

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 substantial, 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 2005 from an annual rate of $0.88 per share to $1.00 per share. The Company's dividend payout ratio remains comparatively low, at approximately 48 percent of 2004 earnings from continuing operations. We expect to grow our dividend payout ratio to the middle of a payout range of 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 order to attract capital. 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 costs, and to earn its allowed rate of return. In accordance with the rate plan, the VPSB approved, and the Company implemented, a 1.9 percent rate increase, effective January 1, 2005.

Power supply expenses were equivalent to approximately 63 percent of total revenues in 2004. 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 included 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 customer concentration 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.

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	
	2004	2003
Consolidated diluted earnings per share of common stock	$ 2.20	$ 2.02
Consolidated diluted earnings per share of common stock-continuing operations	$ 2.10	$ 2.01
Consolidated return on average common equity.	11.06%	10.76%

Earnings from continuing operations improved in 2004 primarily as a result of increased recognition of revenues previously deferred under a VPSB order described below, and from growth in retail sales of electricity to large and small commercial and industrial customers. Higher transmission expenses partially offset these benefits.

Earnings from discontinued operations totaled $.10 per share in 2004 compared with $.01 per share in the prior year, reflecting diminished exposure to outstanding litigation against an inactive Northern Water Resources subsidiary that led to reversal of previously recorded reserves.

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 (generating approximately $4 million in added annual revenues) effective January 1, 2005, and 0.9 percent (generating approximately $2 million in added annual revenues) effective January 1, 2006. The first of these rate increases has been implemented effective January 1, 2005. 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. The 2003 Rate Plan permitted us to continue to defer and recognize these revenues in 2004. We recognized approximately $3.0 million of these deferred revenues to achieve our allowed rate of return during 2004, compared with approximately $1.1 and $4.5 million recognized in 2003 and 2002, respectively.

Retail operating revenues in 2004 increased by $4.5 million or 2.3 percent compared with 2003, reflecting an improving economy, including a modest growth in the number of customers served, and increased recognition of revenues deferred under the 2003 Rate Plan discussed above. Total retail megawatt hour sales of electricity increased by 1.8 percent in 2004, compared with the same period in 2003. Megawatt hour sales of electricity to large and small commercial and industrial customers increased by 3.3 percent and 2.0 percent, respectively, while sales to residential customers were flat when compared with 2003, reflecting milder and more normal weather conditions in 2004.

Wholesale revenues in 2004 decreased by $56.2 million compared with 2003, reflecting reduced sales of electricity to Morgan Stanley Capital Group, Inc., under a contract designed to manage price risks associated with changing fossil fuel prices. The reduction in wholesale revenues did not adversely affect Company earnings in 2004 and is not expected to adversely affect future operating results.

Power supply expenses in 2004 decreased $53.3 million compared with 2003 due to decreased wholesale sales of electricity, principally those associated with the Morgan Stanley contract. Power supply expense also decreased due to reduced expenses to supply an option contract with Hydro Quebec, and an increase in credits resulting from monthly financial transmission rights ("FTR") auctions conducted by ISO New England designed to make regions with inadequate transmission and generation pay a premium for energy delivery.

The Company accounts for its wholly-owned subsidiary, Northern Water Resources ("NWR"), as a discontinued operation. NWR's assets and liabilities consist primarily of deferred tax assets and liabilities relating to a number of investments that the Company has discontinued, deactivated, sold in part or retained as passive minority interests. Remaining holdings include a minority equity investment in a wind project that usually, but not always, generates tax losses; minority interest in a manufacturer of waste treatment equipment; and some non-performing loans. The Company recognized income of $.10 per share from

Discontinued Operations during 2004, compared with earnings of $.01 in 2003, primarily reflecting diminished exposure to outstanding litigation that led to reversal of previously recorded reserves. All of these investments have been written off except for associated deferred tax amounts, net of applicable valuation allowances.

In 2003, the Company reported consolidated earnings of $2.02 per share of common stock, diluted, 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 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 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.

CRITICAL ACCOUNTING POLICIES

Management believes our 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.

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. 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. Costs are deferred as regulatory assets when the Company concludes that future revenue will be provided to permit recovery of the previously incurred cost. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence and legal representations. 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 some other 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 its regulatory assets, net of regulatory liabilities as set forth in the table below:

REGULATORY ASSETS AND LIABILITIES

	At December 31, 2004	2003
	(in thousands)	
Regulatory assets:		

Demand-side management programs	$ 7,293	$ 6,713
Purchased power costs	2,322	2,574
Pine Street barge canal	13,250	12,954
Net power supply deferral	12,085	19,734
Other regulatory assets	6,932	8,439
Total regulatory assets	41,882	50,414
Regulatory liabilities:		
Rate levelization liability	-	2,970
Accumulated cost of removal	19,806	21,238
Other regulatory liabilities	4,012	2,643
Total regulatory liabilities	23,818	26,851
Regulatory assets net of regulatory liabilities	$ 18,064	$23,563

The 2003 Rate Plan, approved by the VPSB in December 2003, provides for amortization and recovery of nearly 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.

The net power supply deferral represents the net value of certain power supply contracts that must be marked to fair value as derivatives under current accounting rules. The Company records contract specified prices for electricity as expense in the period used, as opposed to fair market values reflected in the above table, in accordance with accounting required by a VPSB order. The power supply contract expenses are fully recovered in the rates we charge, and are discussed in detail under Power Supply Derivatives.

Regulatory assets represent incurred costs that have been deferred because the Company has concluded that they are probable of future recovery in customer rates. Management's conclusions represent a critical accounting estimate. Regulatory liabilities generally represent obligations to reduce future rates.

Our 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 and net of estimates of electricity lost during transmission, in order to match revenues with related costs.

The Company's defined benefit plan cost can vary significantly based on plan assumptions and results including the following factors: interest rates, healthcare cost trends, return on assets and compensation cost trends.

Management also exercises judgments about the expected outcome of litigation for contingencies. If the Company determines that it is probable that it will sustain a loss associated with pending litigation, regulatory proceedings or tax matters, and if it can estimate the likely amount of such loss, it will record a liability for that amount.

Our critical accounting policies are discussed further 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," in Note H, "Pension and Retirement Plans" and in Note I, "Commitments and Contingencies."

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, benefit plan cost sensitivity to interest rates and healthcare cost inflation and weather. Discussion of these and other risks, as well as factors contributing to mitigation of these risks, follows.

POWER SUPPLY RISKS.

POWER CONTRACT COMMITMENTS - 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 ("VYNPC") Contract (the "VYNPC Contract"), which together supply approximately 75 percent of our retail load. The Company has also entered into a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") designed to manage wholesale electricity price risks associated with changing fossil fuel prices. The Morgan Stanley Contract supplies an additional 16 percent of our load and expires December 31, 2006. The VJO and VYNPC contracts are summarized in the following table.

	2004 MWh	2004 $/MWh	2003 MWh	2003 $/MWh	Contract Expires
VJO Contract.	605,718	$74.47	664,225	$69.81	2015
Vermont Yankee Contract	764,010	$43.63	884,585	$43.08	2012

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.

On July 31, 2002, VYNPC completed the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee LLC ("ENVY"). As part of the sale transaction, VYNPC entered into a Power Purchase Agreement ("PPA") with ENVY under 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 generally range from $39 to $45 per MWh. 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. We no longer bear the operating costs and risks associated with running and decommissioning the plant. If market prices rise, however, PPA prices are not adjusted upward in excess of the contract price. 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.

In addition to the VJO and VYNPC contracts, the Company entered into the Morgan Stanley Contract in 1999. In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006. The Morgan Stanley Contract price is substantially below current market prices. The Morgan Stanley Contract currently supplies approximately 16 percent of the Company's estimated customer demand ("load").

Under the Morgan Stanley Contract, on a daily basis, and at Morgan Stanley's discretion, we sell power to Morgan Stanley from part of our portfolio of power resources at pre-defined operating and pricing parameters. Morgan Stanley sells to the Company, at a pre-defined price, power sufficient to serve pre-established load requirements. We remain responsible for resource performance and availability. The Morgan Stanley Contract provides no coverage against major unscheduled power supply outages. Beginning January 1, 2004, the Company reduced the power that it sells pursuant to the Morgan Stanley Contract. The output of some of our power-supply resources, including purchases pursuant to our Hydro Quebec and VYNPC contracts, which were sold to Morgan Stanley through 2003, are no longer included in the Morgan Stanley Contract. This reduction in sales to Morgan Stanley reduced wholesale revenues by approximately $56.2 million during 2004 when compared with 2003, and correspondingly reduced power supply expense by a similar amount. This change did not adversely affect the Company's operating results or its opportunity to earn its allowed rate of return during 2004.

In 1996, the Company entered into an agreement with Hydro Quebec ("the 9701 agreement") under which Hydro Quebec paid $8.0 million to the Company in 1997 and we provided Hydro Quebec options for the purchase of power in specified maximum amounts through 2015, as discussed below under "Power Supply Risk."

POWER SUPPLY PRICE RISK - All of the Company's power supply contract costs are currently being recovered through rates approved by the VPSB. The Company records the annual cost of power obtained under long-term contracts as operating expenses. The Company meets the majority of its customer demand through a series of long-term physical and financial contracts. There are occasions when the available supply of electricity is insufficient to meet customer demand. During those periods, electricity is purchased at market prices.

We expect approximately 90 percent of our estimated load requirements through 2006 to be met by our contracts and generation and other power supply resources. These contracts and resources significantly reduce the Company's exposure to volatility in wholesale energy market prices.

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 from or sell the difference into a marketplace that has experienced volatile energy prices. Market price trends also may make it more difficult to extend or enter into new power supply contracts at prices that avoid the need for rate relief. Vermont does not have an automatic fuel adjustment clause or similar mechanism to adjust rates for higher energy costs without prior regulatory approval.

The Company has established a risk management program designed to mitigate some of the potential adverse cash flow and income statement effects caused by power supply risks, including credit risks associated with counterparties. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and the sale or purchase of 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, ENVY and Morgan Stanley, all currently have investment grade credit ratings.

POWER SUPPLY DERIVATIVES.

The Morgan Stanley Contract is used to hedge our power supply costs against increases in fossil fuel prices. The Morgan Stanley Contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133"). Management has estimated the fair value of the future net benefit of this agreement at December 31, 2004 to be approximately $10.7 million.

The Company is unable to predict the price, contract duration or terms of any future power supply contract that could replace the Morgan Stanley Contract after it expires on December 31, 2006.

The Company's 9701 agreement with Hydro Quebec grants Hydro Quebec an option to call power at prices that are now expected to be below estimated future wholesale market prices. 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. 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, 2004, Hydro Quebec had purchased 566,000 MWh under option B. The Company expects Hydro Quebec to call its remaining entitlements of approximately 34,000 MWh under option B during 2005.

Hydro Quebec exercised options A and B for 2004, and the Company 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. 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. The 9701 agreement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for this agreement at December 31, 2004 is approximately $22.8 million. We sometimes use forward contracts to hedge forecasted calls by Hydro Quebec under the 9701 agreement and treat such contracts as derivatives under SFAS 133.

The table below presents assumptions used to estimate the fair value of the Morgan Stanley Contract and the 9701 agreement. 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	2.0%	32%-29%	$ 62	2006
9701 Arrangement. . . .	Black-Scholes	4.3%	46%-27%	$ 66	2015

The table below presents the Company's estimated 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 $1.5 million. Actual results may differ materially from the table illustration.

Commodity Price Risk	December 31, 2004 Fair Value(Cost)	Market Risk
	(in thousands)	

Morgan Stanley Contract	$ 10,736	$ 1,953
9701 agreement.	(22,821)	(3,487)
	$ (12,085)	$ (1,534)

Under an accounting order issued by the VPSB, changes in the fair value of derivatives are deferred. If a derivative instrument were terminated early because it is probable that a transaction or forecasted transaction will not occur, any gain or loss would be recognized in earnings immediately. For derivatives held to maturity, the earnings impact is recorded in the period that the derivative is sold or matures.

OTHER POWER SUPPLY RISK.

Under the VJO Contract, Hydro Quebec has the right to reduce the load factor from 75 percent to 65 percent a total of three times over the life of the contract. Hydro Quebec exercised the first of these load reduction options, effective for the year 2003. 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 increased power supply expense in 2004 by approximately $1.8 million. Hydro Quebec exercised its third and final option in 2004 to reduce deliveries occurring principally during 2005, resulting in an estimated cost of replacement power of $1.8 million, based on current wholesale market prices for 2005. It is possible our estimate of future power supply costs could differ materially from actual results. The Vermont Joint Owners, including the Company, retain two options to increase the load factor to 80 percent from 75 percent after 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.

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 energy costs.

Our VJO contract contains 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.

In accordance with guidance set forth in FASB Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others ("FIN 45"), the Company is required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood of triggering the guarantee is remote. In regards to the "step-up" provision in the VJO Contract, the Company must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. The Company believes this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power. Despite the remote chance that such an event could occur, the Company estimates that its undiscounted purchase obligation would be approximately $880 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2005 and remained in default for the duration of the contract. In such a scenario, the Company would then own the power and could seek to recover its costs from the defaulting members, its retail customers, and/or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

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. During 2003, another unscheduled outage resulted in the Company's deferral of approximately $500,000 of added power supply costs. While the Vermont Yankee plant has had an excellent operating record, future unscheduled outages could occur at times when replacement energy costs are above VYNPC Contract costs. Historically, the VPSB has allowed the Company to defer, rather than expense, the higher costs resulting from extraordinary outages at the plant. Since the Company no longer owns an interest in the Vermont Yankee nuclear plant, we are not responsible for any fixed costs at the plant, the costs of decommissioning the plant, nor are we responsible for any plant repairs or maintenance costs during outages.

On June 18, 2004, a fire in the electrical conduits leading to a transformer outside the plant resulted in a shutdown of the ENVY plant. The outage ended on July 7, 2004. In response to the Company's request, the VPSB issued a final accounting order allowing the Company to defer its incremental replacement power costs during the outage totaling approximately $500,000. The order also instructs the Company to apply any proceeds received under a Ratepayer Protection Plan ("RPP") to reduce the balance of deferred replacement power costs. ENVY disputes that the fire was uprate-related. The Company has petitioned the VPSB to resolve the dispute.

The RPP was a part of ENVY's request to uprate or increase the output of the VY nuclear plant that was approved by the VPSB. Under the RPP, we have indemnification rights to between approximately $550,000 and $1.6 million to recover uprate-related reductions in output for the three-year period beginning in May 2004 and ending after completion of the uprate (or a maximum of three years), depending on future wholesale energy market prices.

ENVY has announced that, under current operating parameters, it will exhaust the capacity of its existing nuclear waste storage pool in 2007 or 2008 and will need to store nuclear waste in so-called "dry fuel storage" facilities to be constructed on the site. Current Vermont law appears to require ENVY to obtain approval of the Vermont State legislature, in addition to VPSB approval, to construct and use such dry fuel storage facilities. If ENVY is unsuccessful in receiving favorable legislative action and/or regulatory approval, ENVY has announced that it could be required to shut down the VY plant between 2007 and 2008. If the VY plant is shut down in 2007 or 2008, we would have to acquire substitute baseload power resources, comprising approximately 35 percent of our load. At currently projected market prices, we estimate the annual incremental cost (in excess of the projected costs of power under our power supply contract for output from the VY facility) would be approximately $9 million per year. Recovery of those increased costs in rates would require a rate increase of approximately 5 percent.

In April 2004, ENVY reported that two short spent fuel rod segments were not in what ENVY believed to be their documented location in the spent fuel pool. After initial review and visual inspection of the spent fuel pool, ENVY did not locate the fuel rod segments. By letter dated May 5, 2004, ENVY notified VYNPC that based on the terms of the Purchase and Sale Agreement dated August 1, 2001, and facts at that time, it was ENVY's view that costs associated with the spent fuel rod segment inspection effort were the responsibility of VYNPC. VYNPC responded that based on the information at that time, there was no basis for ENVY to claim the inspection was VYNPC's responsibility. Subsequently, ENVY discovered the fuel rod segments in a container in the spent fuel pool. We cannot predict the outcome of this matter at this time.

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. "SFAS 71" 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.

The Company has recognized revenues deferred under previous regulatory orders to help it earn its allowed rate of return (see "Earnings Summary"). The Company's ability consistently to achieve its allowed rate of return is likely to be more uncertain prospectively due to the absence of available deferred revenues, unless it secures appropriate and adequate rate increases to cover its costs of operation.

The Company invests in its utility infrastructure to serve its customers. Obtaining a return on that investment is a component in a rate increase proceeding that typically lasts for a period of approximately eight and one-half months. Uncertainty regarding the outcome of rate proceedings contributes to the risk that we will not achieve our allowed rate of return in any given year.

Regulatory risk is also affected by the amount of rate relief that the Company needs to achieve its allowed rate of return. Since 2001, the Company has not needed any substantial rate relief. In August 2002 we extended our Morgan Stanley Contract before wholesale market power supply prices increased and we have been able to pass those benefits along to our customers. Our retail revenue needs through 2006 are covered by our 2003 Rate Plan. The current Morgan Stanley Contract expires on December 31, 2006. We estimate that we will need a rate increase of approximately 5 to 6 percent effective January 1, 2007, driven primarily by replacement power costs for our Morgan Stanley Contract (if the Morgan Stanley Contract was replaced at current market prices), and higher projected transmission expenses.

Central Vermont Public Service Corporation ("CVPS") is currently subject to a rate investigation by the VPSB. In that case, the DPS has advocated positions that, if adopted by the VPSB and applied to the Company, could adversely affect our cash flows and operating results. Areas of risk include:

* The Department's advocacy for an earnings cap calculation that would potentially subject all items on the balance sheet and income statement to a

retroactive review in order to determine whether the Company has met or exceeded the earnings cap. Our 2003 Rate Plan provides that the Company operate under an earnings cap through 2006. The Company calculates its earnings under the cap in a manner that differs from the methodology advocated by the DPS in the CVPS rate proceeding.

* DPS advocacy for elimination or reduction of costs of future removal that are currently embedded in depreciation rates and reflected in our cash flows. The methodology we currently employ is consistent with that used in most other regulatory jurisdictions.

* DPS advocacy for reduced rates of return on equity for CVPS.

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, 2004, the Company would write-off its regulatory assets, net of regulatory liabilities (see above discussion "Critical Accounting Policies"). 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. The largest category of costs that could be subject to the risk of non-recovery in rates in the event of electric utility restructuring in Vermont ("stranded costs") are those relating to our 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 $56 million and $96 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 can be estimated.

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, 24.1 and 25.7 percent of the Company's retail MWh sales in 2004, 2003 and 2002, respectively, and 16.4, 16.6 and 17.3 percent of the Company's retail operating revenues in 2004, 2003 and 2002, 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.

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 increased by approximately $350,000 in 2004 compared with 2003. 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 necessitate a retail rate increase for all our remaining customers of approximately five 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 approximately $2.2 million and $3.5 million to its defined benefit plans during 2004 and 2003, respectively, and we expect to contribute between $2.0 and $3.0 million during 2005.

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. In 2004, a reduction in the pension plan's discount rate was primarily responsible for increasing the OCI charge and related net liability by approximately $566,000. The 2002 and 2004 OCI charge and the 2003 OCI benefit had no effect on net income.

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 2005. 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, megawatt hour ("MWh") sales and number of customers for the years ended 2004, 2003 and 2002 were as follows:

	Years ended December 31, 2004	2003	2002
(dollars in thousands)			
Operating Revenues			
Retail*	$ 203,218	$ 198,717	$ 201,052
Sales for Resale. . .	22,652	78,901	70,646
Other	2,946	2,852	2,910
Total Operating Revenues.	$ 228,816	$ 280,470	$ 274,608
MWH Sales-Retail.	1,969,925	1,934,340	1,948,190
MWH Sales for Resale. . .	411,769	2,287,039	2,107,941
Total MWH Sales	2,381,694	4,221,379	4,056,131

*Retail revenues include $3.0 million, $1.1 million and $4.5 million of deferred revenue recognized for 2004, 2003, and 2002, respectively.

Comparative changes in operating revenues are summarized below:

Average Number of Customers

	Years ended December 31, 2004	2003	2002
Residential	75,507	74,693	73,861
Commercial and Industrial	13,539	13,369	13,194
Other	62	65	65
Total Number of Customers. .	89,108	88,127	87,120

Change in Operating Revenues	2003 to 2004	2002 to 2003	2001 to 2002
	(In thousands)		
Retail Rates.	$ 830	$ (912)	$ 6,471
Retail Sales Volume	3,671	(1,423)	(512)
Resales and Other Revenues.	(56,155)	8,197	(14,815)
Increase (Decrease) in Operating Revenues	$ (51,654)	$ 5,862	$ (8,856)

Nearly all of the Company's earnings from continuing operations are typically generated by retail sales of electricity. In 2004, retail revenues increased $4.5 million or 2.3 percent compared with 2003, due to

An increase of $1.9 million in recognition of revenues deferred under the 2003 Rate Plan;
A 3.3 percent increase in megawatt hour sales to large commercial and industrial customers resulting in a $1.4 million increase in revenue; and
A 2.0 percent increase in megawatt hour sales to small commercial and industrial customers resulting in a $1.0 million increase in revenue.

Residential retail revenues and megawatt hour sales of electricity were up only 0.1 percent in 2004, compared with 2003. We experienced residential customer growth in 2004, but 2004 weather conditions were less favorable for electricity sales than 2003.

Wholesale revenues decreased in 2004 by $56.2 million, or 71.3 percent, compared with 2003, reflecting reduced sales of electricity under the Morgan Stanley Contract. The reduction in sales under the Morgan Stanley Contract did not adversely affect the Company's earnings in 2004 and is not expected to adversely affect the Company's earnings in future years.

In 2003, total electricity sales increased 4.1 percent compared with 2002, due to increased wholesale sales and sales to residential and small commercial and industrial customers, partially offset by decreased sales to large commercial and 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 agreement;
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 $4.5 million recognized in 2002; and
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.

POWER SUPPLY EXPENSES - Power supply expenses constituted 67.5, 74.4 and 74.5 percent of total operating expenses for the years 2004, 2003 and 2002, respectively. The decreased 2004 percentage reflects reduced purchases and sales of electricity under the Morgan Stanley Contract.

Power supply expenses decreased by $53.3 million or 27.0 percent in 2004 when compared with 2003, and resulted from the following:

An estimated $56.2 million decrease in the cost of power purchased for resale resulting primarily from the restructuring of the Morgan Stanley Contract described above;
A $1.8 million increase in credits from the ISO New England ("ISO-NE") resulting from FTR auctions designed to make congested regions pay a premium for energy delivery, and credits for certain Company generation; and
A $1.3 million decrease in the net cost of our 9701 agreement with Hydro Quebec.

These decreases were partially offset by increased power supply expenses from the following:

A $1.9 million increase in purchases to supply increased retail sales;

An estimated $1.5 million in purchases to replace reduced energy deliveries under the VJO Contract as a result of problems with the transmission interconnection facilities over which we schedule deliveries; and

An $851,000 increase in the contract price per megawatt hour of electricity purchased under the Morgan Stanley Contract.

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.

OTHER OPERATING EXPENSES - Other operating expenses in 2004 were essentially unchanged from the prior year.

Other operating expenses increased $3.7 million, or 26.6 percent, in 2003 compared with 2002 primarily due to increased employee benefit expenses and expenses related to corporate governance.

TRANSMISSION EXPENSES - Transmission expenses increased $873,000, or 5.9 percent, in 2004 compared with 2003, due to increased charges allocated by ISO-NE for system support in the greater Boston area and expensed engineering studies related to substation and transmission design evaluations. 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.

In 2004, we experienced an increase of approximately $750,000 in transmission expense resulting from system-wide allocation of costs associated with voltage control and reactive power ("VAR") in the greater Boston area. We expect this increased transmission expense to continue in 2005. The Company and other affected load serving entities have requested ISO-NE to modify the applicable market rules to allocate VAR-related costs to the reliability regions responsible for the applicable VAR-related costs.

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

ISO-NE 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.

ISO-NE implemented its Standard Market Design ("SMD") plan governing wholesale energy sales in New England 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 could eventually be determined on a more localized ("nodal") basis. In December 2004, FERC reaffirmed the zone pricing system for New England's SMD, subject to FERC's periodic re-analysis of alternative load zones, based on changes in system conditions. We believe that nodal pricing could result in a material adverse impact on our power supply and/or transmission costs, if adopted.

FERC has granted approval to ISO-NE to become a regional transmission organization ("RTO") for New England. On February 1, 2005, ISO-NE commenced operations as the RTO, providing regional transmission service in New England, with operational control of the bulk power system and responsibility for administering wholesale markets. Commencing with implementation of the RTO, costs associated with certain transmission facilities, known as the Highgate Facilities, of which the Company is a part owner, will be phased into region-wide rates over a 5-year period. When fully phased in, we estimate that this "roll-in" of the Highgate facilities will achieve approximately $1.4 million in annual transmission costs savings for the Company.

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. In January 2005, the project received regulatory approval from the VPSB. The project is estimated to cost approximately $150 million through 2007. VELCO intends to finance the costs of constructing the Northwest Reliability Project in part through increased equity investment. In October 2004, the Company invested $4.6 million in VELCO to support this project and other transmission projects. The Company plans to invest at least $15 million additionally in VELCO through 2007 for the same purpose. Under current NEPOOL and ISO-NE rules, which require qualifying large transmission project costs to be shared among all New England utilities, approximately 95 percent of the pool transmission facility costs of the Northwest Reliability Project will be allocated throughout the New England region, with Vermont utilities responsible for approximately 5 percent of allocated costs. Vermont utilities are required to pay 5 percent of pool transmission facility upgrades in other New England states.

MAINTENANCE EXPENSES - Maintenance expenses increased $25,000, or 0.2 percent, in 2004 compared with 2003 due to increased expenditures on right-of-way maintenance programs offset by decreased expenditures related to gas turbine maintenance.

Maintenance expenses decreased $151,000, or 1.5 percent, in 2003 compared with 2002, due to decreased expenditures related to maintenance of our Searsburg wind generation facility.

DEPRECIATION AND AMORTIZATION - Depreciation and amortization expense increased $129,000, or 0.9 percent, in 2004 compared with 2003 due to increases in depreciation of utility plant in service partially offset by decreased amortization of software costs.

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.

TAXES OTHER THAN INCOME - Taxes other than income taxes decreased $210,000, or 3.0 percent, in 2004 compared with 2003 due to decreased property tax expense.

Taxes other than income taxes decreased $45,000, or 0.6 percent, in 2003 compared with 2002 for the same reason.

INCOME TAXES - Income tax expense increased $642,000, or 12.5 percent, primarily due to an increase in pre-tax income in 2004 compared with 2003.

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

OTHER INCOME AND DEDUCTIONS - Other income and deductions increased $8,000 in 2004 compared with 2003 due primarily to sales of non-utility property offset by reduced earnings on investment in Vermont Yankee.

Other income decreased $406,000, or 16.3 percent, in 2003 compared with 2002 due primarily to VYNPC recognition of deferred tax assets arising in conjunction with the sale of the Vermont Yankee plant and reduced earnings on investment in VYNPC as a result of the sale of the Vermont Yankee plant in 2002.

INTEREST EXPENSE - Interest expense decreased $551,000, or 7.8 percent, in 2004 compared with 2003 primarily due to scheduled redemptions of long-term debt in December 2003.

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.

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.

The Company joined the Chicago Climate Exchange ("CCX"), a self-regulatory exchange that administers a market for reducing and trading greenhouse gas emission credits. We are the first utility in the northeast to join the CCX, and have committed voluntarily to reduce our emissions by 4 percent below our 1998 - 2001 baseline average by 2006, either directly or by purchasing credits.

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 2004 and 2003, the Company expended $1.5 and $2.6 million, respectively, 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 $6.5 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 $13.3 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 by the Company and the DPS. The 2003 Rate Plan covers the period from 2003 through 2006 and includes the following principal elements:

The Company's rates remained 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. We submitted a cost of service schedule supporting the 1.9 percent rate increase for 2005 in accordance with the plan. The increase became effective on January 1, 2005 in accordance with the plan. If the Company's cost of service filing in 2006 established that a rate increase of less than 0.9 percent is required for the Company to meet its revenue requirements, the Company would implement the lesser rate increase. The VPSB retains the discretion to open an investigation of the Company's rates at any time, at the request of the DPS, the request of ratepayers, or on its own volition. Certain ratepayers requested the VPSB to open such an investigation in connection with the Company's 1.9 percent rate increase for 2005. The VPSB granted the request in December 2004, and then, at our request, closed and terminated its investigation in January 2005, with no adverse impact on the Company's rates.

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 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. The Company did not experience excess earnings in 2004. 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 carried 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 were applied in 2004 to offset increased costs.

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 filed with the VPSB in 2004 a new fully-allocated cost of service study and rate re-design, which allocates the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design is 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 was restricted until new rates went into effect, which occurred in January 2005. Although this restriction has expired, we have no plans to make material investments in non-utility operations.

LIQUIDITY AND CAPITAL RESOURCES

Our cash, net working capital and net operating cash flows are as follows:

(In thousands)	At December 31, 2004	2003
Cash and cash equivalents.	$ 1,720	$ 786
Current assets	$35,462	$31,688
Less current liabilities	24,468	22,715
Net working capital.	$10,994	$ 8,973
Net cash provided by operating activities.	$26,162	$21,070

We expect most of our construction expenditures and dividends to be financed by net cash provided by operating activities. We anticipate that we will issue long-term debt of approximately $25 million in 2006 for scheduled first mortgage bond redemptions of $14 million and to refinance accumulated short-term debt. Material risks to cash flow from operations include regulatory risk, our customer concentration risk with IBM, slower than anticipated load growth, unfavorable economic conditions and increases in net power costs.

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, including $4.6 million invested during 2004. Our planned investments will fund in part an increase in the amount of equity in VELCO's capital structure and increased investment, principally driven by construction of the Northwest Reliability Project and other Vermont construction projects. See detailed discussion under "Transmission Expenses."

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 over the past three years and forecasted for 2005 are as follows:

(In thousands)	Generation	Transmission	Distribution	Other*	Total
Actual:					
2002	$ 3,258	$ 1,827	$ 9,173	$ 7,479	$21,737
2003	2,629	1,496	7,760	6,622	18,507
2004	3,053	2,898	10,908	5,005	21,864

Forecast:					
2005	$ 3,264	$ 3,234	$ 10,156	$ 6,122	$22,776

* Other includes Pine Street Barge Canal net expenditures of $1.8 million in 2002, $2.5 million in 2003, $1.2 million in 2004 and an estimated $750,000 in 2005.

DIVIDEND POLICY - On February 14, 2005, the annual dividend rate was increased from $0.88 per share to $1.00 per share, a payout ratio of approximately 48 percent based on 2004 earnings from continuing operations. 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 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. The Company expects to increase the dividend in the first quarter of each year until the payout ratio falls in the middle of a payout range of 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.

FINANCING AND CAPITALIZATION

During June 2004, 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 $30.0 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 $3.0 million outstanding on the Fleet-Sovereign Agreement at December 31, 2004 at an average rate of 5.25 percent. There was no non-utility short-term debt outstanding at December 31, 2004 or 2003. The Fleet-Sovereign Agreement expires June 15, 2005. The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2005.

During 2002, we redeemed $5.1 million of 10.0 percent first mortgage bonds and $12.5 million of outstanding preferred stock.

In 2002, 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.

The credit ratings of the Company's first mortgage bonds at December 31, 2004 were:

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

On June 18, 2004 Moody's affirmed the Company' senior secured debt rating at Baa1, with a stable outlook. On November 3, 2004, Standard and Poor's Ratings Services upgraded the Company's issuer credit rating to BBB from BBB-, citing an improved regulatory climate in Vermont. Standard and Poor's Ratings Services also 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 either of the credit rating agencies listed above.

The following table presents a summary of certain material contractual obligations existing as of December 31, 2004.

At December 31, 2004		Payments Due by Period			
	TOTAL	2005	2006 and 2007	2008 and 2009	After 2009
(In thousands)					
Long-term debt	$ 93,000	$ -	$ 14,000	$ -	$ 79,000
Interest on long-term debt	70,170	6,534	12,068	11,068	40,500
Capital lease obligations.	4,516	572	879	766	2,299
Hydro-Quebec power supply contracts.	574,044	50,960	100,986	102,723	319,375
Morgan Stanley Contract.	22,718	12,561	10,157	-	-
Independent Power Producers.	183,217	15,905	33,923	32,808	100,581
Stony Brook contract	46,808	2,876	6,024	6,506	31,402
VYNPC PPA.	255,588	33,047	68,090	71,590	82,861
Total.	$1,250,061	$122,455	$246,127	$225,461	$656,018

See the captions "Power Supply Expense" and "Power Contract Commitments" for additional information about the Hydro-Quebec and MS power supply contracts

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 pay a portion of VELCO's operating costs, including its debt service costs.

OTHER RISKS - The Town of Rockingham, Vermont, located in the southeastern portion of our service territory, has exercised an option to purchase a hydro-electric facility partially located in the town (the "Bellows Falls facility"). If Rockingham or its assignee is successful in arranging for purchase of the Bellows Falls facility, we expect to conclude an agreement to permit Rockingham to be responsible for its own power supply needs, with the Company providing distribution and other services to the town. In any such agreement the Company would continue to own its distribution plant located in the town and receive distribution services revenues sufficient to cover all costs of providing services and all stranded costs associated with the Company's present obligation to provide integrated electric service to customers in Rockingham. Such an arrangement would require VPSB approval. The Company receives annual revenues of approximately $3 million from its customers in Rockingham.

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 received VPSB approval for, and has made additional dam improvements, at the facility. The VPSB has pending a regulatory proceeding to determine whether to impose regulatory penalties in connection with the 1995 dam improvements.

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

	For the Years Ended December 31		
	2004	2003	2002
(In thousands, except per share data)			

Retail and other revenues	$206,164	$201,569	$203,962
Wholesale revenues	22,652	78,901	70,646
TOTAL OPERATING REVENUES	228,816	280,470	274,608
Operating expenses-Power Supply:			
Purchases from others	137,503	189,450	188,381
Company-owned generation	6,516	7,856	5,067
Other operating	17,537	17,534	13,851
Transmission	15,656	14,783	15,221
Maintenance	9,746	9,721	9,872
Depreciation and amortization	13,931	13,803	14,151
Taxes other than income	6,687	6,897	6,942
Income taxes	5,762	5,120	6,043
Total operating expenses	213,338	265,164	259,528
OPERATING INCOME	15,478	15,306	15,080
OTHER INCOME			
Equity in earnings of affiliates and non-utility operations	1,232	1,493	2,777
Allowance for equity funds used during construction	449	387	233
Other income	714	409	393
Other deductions	(308)	(210)	(918)
Total other income	2,087	2,079	2,485
INTEREST CHARGES			
Long-term debt	6,534	7,021	5,214
Other	257	303	1,059
Allowance for borrowed funds used during construction	(285)	(267)	(103)
Total interest charges	6,506	7,057	6,170
INCOME FROM CONTINUING OPERATIONS BEFORE PREFERRED DIVIDENDS	11,059	10,328	11,395
Dividends on preferred stock	-	3	96
INCOME FROM CONTINUING OPERATIONS	11,059	10,325	11,299
Income from discontinued operations, net	525	79	99
NET INCOME APPLICABLE TO COMMON STOCK	$ 11,584	$ 10,404	$ 11,398
EARNINGS PER SHARE			
Basic earnings per share from continuing operations	$ 2.18	$ 2.08	$ 2.02
Basic earnings per share from discontinued operations	0.10	0.01	0.02
Basic earnings per share	$ 2.28	$ 2.09	$ 2.04
Diluted earnings per share from continuing operations	$ 2.10	$ 2.01	$ 1.96
Diluted earnings per share from discontinued operations	0.10	0.01	0.02
Diluted earnings per share	$ 2.20	$ 2.02	$ 1.98
Weighted average shares outstanding-basic	5,083	4,980	5,592
Weighted average equivalent shares outstanding-diluted	5,254	5,140	5,756

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years E December	
	2004	2003
OPERATING ACTIVITIES	(in thousands)	
Income from continuing operations before preferred dividends	$ 11,059	$ 10,328
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization.	13,931	13,803
Dividends from associated companies.	863	2,081
Equity in undistributed earnings of associated companies	(880)	(1,197
Allowance for funds used during construction	(733)	(654
Amortization of deferred purchased power costs	318	318
Deferred income tax expense, net of investment tax credit amortization	3,699	1,479
Deferred purchased power costs	(667)	(570
Rate levelization liability.	(2,970)	(1,121
Environmental and conservation deferrals, net.	(1,041)	(1,890
Cash in advance of construction.	2,246	1,222
Gain on sale of property	(402)	-
Share-based compensation	1,244	-
Changes in:		
Accounts receivable and accrued utility revenues	(1,120)	(189
Prepayments, fuel and other current assets	(418)	(1,188
Accounts payable and other current liabilities	1,567	(676
Income taxes payable and receivable.	(2,069)	(2,183
Other.	1,009	1,428
Net cash provided by continuing operations	25,637	20,991
Net income from discontinued operations.	525	79
Net cash provided by operating activities.	26,162	21,070
INVESTING ACTIVITIES		
Construction expenditures.	(20,823)	(16,617
Restriction of cash for renewable energy investments	(354)	-
Proceeds from sale of property	648	-
Investment in associated companies	(4,579)	(108
Return of capital from associated companies.	314	7,615
Investment in nonutility property.	(338)	(198
Net cash used in investing activities.	(25,132)	(9,308
FINANCING ACTIVITIES		
Proceeds from issuance of long-term debt	-	-
Repurchase of preferred stock.	-	(85
Payments to acquire treasury stock	-	(3
Issuance of common stock	1,885	995
Reduction in long-term debt and term loan.	-	(8,000
Short-term debt.	2,500	(2,000
Cash dividends	(4,481)	(3,792
Net cash provided by (used in) financing activities.	(96)	(12,885

Net increase in cash and cash equivalents.		934		(1,123
Cash and cash equivalents at beginning of period		786		1,909
blank				
Cash and cash equivalents at end of period	$	1,720	$	786

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION
Cash paid for:

Interest	$	6,691	$	7,120
Income taxes		3,043		2,915

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

(in thousands)	December 31 2004	2003
ASSETS		
UTILITY PLANT		
Utility plant, at original cost	$339,269	$324,900
Less accumulated depreciation	119,633	110,111
Utility plant, net of accumulated depreciation.	219,636	214,789
Property under capital lease.	4,731	5,047
Construction work in progress	8,345	9,026
Total utility plant, net.	232,712	228,862
OTHER INVESTMENTS		
Associated companies, at equity	10,179	5,896
Other investments	8,780	7,810
Total other investments	18,959	13,706
CURRENT ASSETS		
Cash and cash equivalents	1,720	786
Accounts receivable, less allowance for doubtful accounts of $620 and $690.	18,216	17,331
Accrued utility revenues.	6,964	6,729
Fuel, materials and supplies, average cost. . .	4,848	4,498
Prepayments	1,674	1,922
Income tax receivable	1,717	422
Other	323	-
Total current assets.	35,462	31,688
DEFERRED CHARGES		
Demand side management programs	7,293	6,713
Purchased power costs	2,322	2,574
Pine Street Barge Canal	13,250	12,954
Net power supply deferral	12,085	19,734
Power supply derivative asset	10,736	3,990

Other regulatory assets	6,932	8,439
Other deferred charges	1,113	1,186
Total deferred charges	53,731	55,590
NON-UTILITY		
Other current assets	-	217
Property and equipment	247	248
Other assets	508	640
Total non-utility assets	755	1,105
TOTAL ASSETS	$341,619	$330,951

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31 2004	2003
(in thousands except share data)		
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,968,118 and 5,860,854)	$ 19,894	$ 19,536
Additional paid-in capital	78,852	76,081
Retained earnings	29,889	22,786
Accumulated other comprehensive income	(2,353)	(1,787)
Treasury stock, at cost (827,639 shares)	(16,701)	(16,701)
Total common stock equity	109,581	99,915
Long-term debt, less current maturities	93,000	93,000
Total capitalization	202,581	192,915
CAPITAL LEASE OBLIGATION	4,493	4,963
CURRENT LIABILITIES		
Short-term debt	3,000	500
Accounts payable, trade and accrued liabilities	9,437	8,493
Accounts payable to associated companies	7,391	6,821
Rate levelization liability	-	2,970
Accrued taxes	1,290	633
Customer deposits	1,063	968
Interest accrued	1,136	1,152
Other	1,151	1,178
Total current liabilities	24,468	22,715
DEFERRED CREDITS		
Power supply derivative liability	22,821	23,724

Accumulated deferred income taxes.	32,223	30,000
Unamortized investment tax credits	2,564	2,848
Pine Street Barge Canal cleanup liability. . . .	6,458	7,356
Accumulated cost of removal.	19,806	21,238
Deferred compensation.	8,872	8,936
Other regulatory liabilities	4,012	2,643
Other deferred liabilities	11,150	11,536
Total deferred credits	107,906	108,281
COMMITMENTS AND CONTINGENCIES, NOTE 3		
NON-UTILITY		
Net liabilities of discontinued segment.	2,171	2,077
Total non-utility liabilities.	2,171	2,077
TOTAL CAPITALIZATION AND LIABILITIES	$341,619	$330,951

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

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
AND COMPREHENSIVE INCOME

(In thousands except share data)	COMMON STOCK SHARES	AMOUNT	PAID-IN CAPITAL	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME	TR S
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)	-	-	-	-	(1
Compensation programs	52,804	177	342	-	-	
Income before preferred dividends . . .	-	-	-	11,494	-	
Other comprehensive income(loss). . . .	-	-	-	-	(2,374)	
Common stock dividends-$0.60 per share.	-	-	-	(3,297)	-	
Preferred stock dividends	-	-	-	(96)	-	
BALANCE, DECEMBER 31, 2002.	4,954,857	19,276	75,347	16,171	(2,374)	(1
Common stock issuance:						
Compensation programs	78,358	260	734	-	-	
Common stock repurchase	-	-	-	-	-	
Income before preferred dividends . . .	-	-	-	10,407	-	
Other comprehensive income(loss). . . .	-	-	-	-	587	
Common stock dividends-$0.76 per share.	-	-	-	(3,789)	-	
Preferred stock dividends	-	-	-	(3)	-	
BALANCE, DECEMBER 31, 2003.	5,033,215	19,536	76,081	22,786	(1,787)	(1
Common stock issuance:						
Compensation programs	107,264	358	2,771	-	-	
Net income.	-	-	-	11,584	-	

Other comprehensive income(loss). . . .	-	-	-	-	(566)	
Common stock dividends-$0.88 per share.	-	-	-	(4,481)	-	
BALANCE, DECEMBER 31, 2004.	5,140,479	$19,894	$ 78,852	$ 29,889	$(2,353)	$(1

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In thousands	For the years ended December 31, 2004	2003	2002
Net income	$11,584	$10,404	$11,398
Minimum pension liability adjustment, net of applicable income taxes of $391 benefit, $400 expense and $1.6 million benefit, respectively	(566)	587	(2,374) -
Other comprehensive income.	$11,018	$10,991	$ 9,024

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION AND BASIS OF PRESENTATION. Green Mountain Power Corporation (the "Company") is an investor-owned electric utility that transmits, distributes and sells electricity and utility construction services 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 electricity to approximately 90,000 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 "VYNPC").

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 section of the Consolidated Statements of Income. Summarized financial information for GMP Real Estate Corporation and the Company's unregulated water heater program is as follows:

In thousands	Years ended December 31, 2004	2003	2001
Revenue. . .	$ 961	$1,087	$ 997
Expense. . .	594	704	744

Net Income .	$ 367	$ 253	$ 263
	=====	======	=====

The Company accounts for its investments in VYNPC, 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 for additional information.

The Company's interests in jointly-owned generating and transmission facilities are accounted for on a pro-rata basis using the Company's ownership percentages and are recorded in the Company's Consolidated Balance Sheets. The Company's share of operating expenses for these facilities is included in the corresponding operating accounts on the Consolidated Statements of Income.

USE OF ESTIMATES. In preparing the Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Financial Statements, and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Financial Statements particularly as they relate to unbilled revenue, pension expense and contingencies. However, the Company believes it has taken reasonable positions, where assumptions and estimates are used, in order to minimize the impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of unbilled revenue, pension plan assumptions, contingency reserves, accumulated removal obligations, regulatory assets and liabilities, the allowance for uncollectible accounts receivable and derivative valuation.

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. Incurred costs are deferred as regulatory assets when the Company concludes that future revenue will be provided to permit recovery of the previously incurred cost. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence and legal representations.

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, net of regulatory liabilities as summarized in the following table:

REGULATORY ASSETS AND LIABILITIES

	At December 31, 2004	2003
Regulatory assets:	(in thousands)	
Demand-side management programs	$ 7,293	$ 6,713
Purchased power costs	2,322	2,574
Pine Street barge canal	13,250	12,954
Net power supply deferral	12,085	19,734
Other regulatory assets	6,932	8,439
Total regulatory assets	41,882	50,414
Regulatory liabilities:		
Rate levelization liability	-	2,970
Accumulated cost of removal	19,806	21,238
Other regulatory liabilities.	4,012	2,643
Total regulatory liabilities.	23,818	26,851
Regulatory assets net of regulatory liabilities	$ 18,064	$23,563

*Substantially all regulatory assets are being recovered in current rates effective January 1, 2005 and, with the exception of Pine Street Barge Canal and certain power contract related costs, include an associated return on investment.

The net power supply deferral results from certain power supply contracts that must be marked to fair value as derivatives under current accounting rules. The Company records contract specified prices for electricity as expense in the period used, as opposed to fair market values reflected in the above table. The power supply contract expenses are fully recovered in the rates we charge, and are discussed in detail under Power Supply Derivatives.

The Company defers and amortizes replacement power costs associated with unscheduled outages at the Vermont Yankee nuclear power plant owned by Entergy Nuclear Vermont Yankee LLC ("ENVY') and other extraordinary losses. The Company also defers and amortizes extraordinary costs associated with natural disaster, severe storms costs or significant loss of load under a rate plan (see Note I, Commitments and Contingencies).

Other regulatory assets totaled $6.9 million and $8.4 million at December 31, 2004 and 2003, respectively, and consist 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.

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. The Company provides for regulatory disallowances when management believes it is both probable and estimable that a regulatory liability exists.

Accumulated costs of removal represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS 143, "Accounting for Asset Retirement Obligations," the Company reflects these amounts as a regulatory liability. Prior to SFAS 143, these amounts were recorded as a part of the Company's Accumulated Depreciation. We expect, over time, to recover or settle through future revenues any under- or over-collected net cost of removal.

DISCONTINUED OPERATIONS. The Company accounts for its wholly-owned subsidiary, Northern Water Resources ("NWR") as a discontinued operation. NWR's assets and liabilities consist primarily of deferred tax assets and liabilities relating to a number of investments that the company has discontinued, inactivated, sold in part or retains as passive minority interests. Remaining holdings include a minority equity investment in a wind project that usually, but not always, generates tax losses; minority interest in a manufacturer of waste treatment equipment; and non-performing loans. The Company recognized income of $.10 per share from Discontinued Operations during 2004, compared with earnings of $.01 and $.02 in 2003 and 2002, respectively, reflecting diminished exposure to outstanding litigation that led to reversal of previously recorded reserves. Substantially all of NWR's investments have been written off except for associated deferred tax amounts, net of applicable valuation allowances.

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 cash flows would be re-valued 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, 2004, 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.

UTILITY PLANT. The cost of plant additions is recorded at original cost and includes all construction-related direct labor and materials, as well as indirect construction costs. The cost of plant additions includes the cost of money ("Allowance for Funds Used During Construction" or "AFUDC") when costs applicable to construction work in progress have not otherwise been provided a return through regulatory proceedings. The costs of renewals and improvements of property units are capitalized. The costs of maintenance, repairs and replacements of minor property items are charged to maintenance expense. The costs of units of property removed from service, net of salvage value, are charged to accumulated depreciation. The following table summarizes the Company's investments in utility plant.

Property Summary at December 31,

In thousands	2004	2003
Property, Plant and Equipment:		
Intangible.	$ 12,390	$ 14,091
Generation.	72,156	68,532
Transmission.	39,368	37,093
Distribution.	186,863	178,292
General, including transportation	28,492	26,892
Total Plant in Service.	339,269	324,900
Accumulated Depreciation and Amortization	(119,633)	(110,111)
Net Plant in Service.	219,636	214,789
Capital Lease	4,731	5,047
Construction Work in Progress	8,345	9,026
Total Net Utility Plant	$ 232,712	$ 228,862

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

The annual depreciation provision was approximately 3.3 percent during 2004, 3.3 percent during 2003 and 3.2 percent during 2002 of total depreciable property.

DISPOSAL OF ASSETS. During 2004, the Company sold non-utility property consisting of land and buildings for $648,000. The Company recognized a gain of approximately $402,000 related to the sale of these assets, which is recorded in Other Income in the Consolidated Statement of Income.

CASH AND CASH EQUIVALENTS. Cash and cash equivalents include short-term investments with original maturities less than ninety days.

RESTRICTED CASH. The Company has set aside $354,000, included in Other Investments, as of December 31, 2004, for renewable generation development under a VPSB regulatory order.

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 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 $3.0 million, $1.1 million and $4.5 million in deferred revenues during 2004, 2003 and 2002, respectively. At December 31, 2004, the Company has recognized all revenues deferred under the VPSB orders. See Note I for additional information.

ALLOWANCE FOR DOUBTFUL ACCOUNTS. The Company estimates the amount of accounts receivable that will not be collected and records these amounts as a reduction to accounts receivable.

Allowance for Doubtful Accounts

In thousands	Balance at Beginning of Period	Additions Charged to Cost & Expenses	Additions Charged to Other Accounts	Deductions	Balance at End of Period
2004	$ 691	$ -	$ -	$ 71	$ 620
2003	547	144	-	-	691
2002	576	-	37	66	547

EARNINGS PER SHARE. Basic earnings per share ("EPS") is calculated by dividing net income, after deductions for preferred dividends, by the weighted-average common shares outstanding for the period. SFAS No. 128, Earnings Per Share, requires the disclosure of diluted EPS, which is similar to the calculation of basic EPS except that the weighted-average common shares is increased by the number of potential dilutive common shares. Diluted EPS reflects the impact of the issuance of common shares for all potential dilutive common shares outstanding during the period, including stock options.

During the year ended December 31, 2000, the Company granted 335,300 options under its 2000 Stock Plan 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. 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,		
	2004	2003	2002
In thousands, except per share amounts			
Net income reported.	$11,584	$10,404	$11,398
Pro-forma net income	$11,503	$10,242	$11,114
Net income per share			
As reported-basic.	$ 2.28	$ 2.09	$ 2.04
Pro-forma basic.	$ 2.26	$ 2.06	$ 1.99
As reported-diluted.	$ 2.20	$ 2.02	$ 1.98
Pro-forma diluted.	$ 2.19	$ 1.99	$ 1.93

MAJOR CUSTOMERS AND OTHER CONCENTRATION RISKS. The Company has one major retail customer, International Business Machines Corporation ("IBM"), that accounted for 24.1 percent, 24.1 percent and 25.7 percent of retail MWh sales, and 16.4 percent, 16.6 percent and 17.3 percent of the Company's retail operating revenues in 2004, 2003 and 2002, respectively.

We currently estimate, based on a number of projected variables, that a hypothetical shutdown of the IBM facility would necessitate a retail rate increase for all remaining customers of approximately five percent, including secondary and tertiary impacts of such a shutdown on other customer sales.

Our material power supply contracts are principally with Hydro Quebec and Vermont Yankee Nuclear Power Corporation ("VYNPC"). These contracts are expected to meet approximately 75 percent of our anticipated annual demand requirements during the next five years. These supplier concentrations could have a material impact on the Company's net power costs, if one or both of these sources were unavailable over an extended period of time. We also have a power supply contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") for approximately 16 percent of our annual load that expires December 31, 2006.

FAIR VALUE OF FINANCIAL INSTRUMENTS. The fair value and carrying 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,			
	2004		2003	
In thousands	Calculated Fair Value	Amount carried on balance sheet	Calculated Fair Value	Amount carried on balance sheet

Long-Term Debt, net,(Note F)	$ 91,274	$ 93,000	$ 91,725	$ 93,000
Derivatives, net	12,085	12,085	19,773	19,773

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.

The fair value of derivatives is discussed below under "Derivative Instruments."

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.

PURCHASED POWER. The Company records the annual cost of power obtained under long-term executory contracts as operating expenses. The contracts do not convey to the Company the right to use the related property plant, or equipment.

DERIVATIVE INSTRUMENTS. The Company utilizes derivative instruments primarily to reduce power supply risk. The Company does not hold derivative trading positions. The Company has continued to record expense related to derivatives in the period settled consistent with an accounting order issued by the VPSB.

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 agreement (the "9701 agreement") that grants Hydro Quebec an option to call power at prices below current and estimated future market rates. This agreement is effective through 2015. From time to time, we use forward contracts to hedge the 9701 agreement. Since we are required under VPSB order to defer recognition of any SFAS 133 earnings effect until settled, we do not evaluate derivatives for hedge accounting treatment. If the Company were to terminate or sell any of its derivative contracts, it would immediately record the gain or loss on that contract, absent a regulatory order to do otherwise.

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

	Option Value	Risk Free	Price	Average	Contract

	Model	Interest Rate	Volatility	Forward Price	Expires
Morgan Stanley Contract	Deterministic	2.0%	32%-29%	$ 62	2006
9701 Arrangement. . . .	Black-Scholes	4.3%	46%-27%	$ 66	2015

At December 31, 2004, the Company had a liability in deferred credits of $22.8 million reflecting the fair value of the 9701 agreement, and an asset of $10.7 million, reflecting the fair value of the Morgan Stanley Contract. A corresponding net regulatory asset of $12.1 million is also recorded in deferred charges. At December 31, 2003, the Company had a liability of $23.7 million, reflecting the fair value of the 9701 agreement, and an asset of $4.0 million, reflecting the fair value of the Morgan Stanley Contract. A corresponding net regulatory asset of $19.7 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. Morgan Stanley purchases a portion of the Company's power supply resources at index (fossil fuel resources) or specified (i.e., contracted resources) prices and then sells to us at a fixed rate to serve pre-established load requirements. This contract allows management to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The Morgan Stanley Contract expires December 31, 2006.

RECLASSIFICATIONS. The Company changed the classification of certain previously reported amounts in the accompanying balance sheet as of December 31, 2003 to correct immaterial errors related to the accounting for income taxes. The effect of the changes was to decrease accumulated deferred income taxes by $4.0 million, increase other deferred credits by $3.4 million, and increase net liabilities of discontinued operations by approximately $600,000. We made conforming changes to the tax footnote and cash flow statement. In addition, certain prior years amounts have been reclassified for consistent presentation with the current year.

OTHER COMPREHENSIVE INCOME. Certain negative scenarios and unfavorable market conditions (asset returns are lower than expected, reductions in discount rates, and liability experience losses) may cause the Pension Plan's accumulated benefit obligation ("ABO") to exceed the fair value of Pension Plan assets as of the measurement date and would result in an unfunded minimum liability. If that occurs, and the minimum liability exceeds the accrued benefit cost, an additional minimum pension liability may be required to be recorded, net of tax, as a non-cash charge to Other Comprehensive Income, included in Common Stock Equity on the Consolidated Balance Sheet. The ABO represents the present value of benefits earned without considering future salary increases.

Other comprehensive loss of $2.4 million, net of a $1.6 million income tax, 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 resulted in a reduction in other comprehensive loss of approximately $587,000, net of $400,000 income tax. During 2004, due principally to a decline in the discount rate used for pension calculations, we recorded an increase in other comprehensive loss of $566,000, net of $391,000 income tax.

RECENT ACCOUNTING PRONOUNCEMENTS. 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 impact the Company's financial position or results of operations. See FIN 45 discussion related to Hydro Quebec under Note K.

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 and December 2003, the Financial Accounting Standards Board issued Interpretation 46 and 46R (Revised), respectively, "Consolidation of Variable Interest Entities" ("VIEs"). This interpretation clarified application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," and replaced current accounting guidance relating to consolidation of certain special purpose entities. FIN 46 and FIN 46R define VIEs as entities that are unable to finance their ongoing operations without additional subordinated financing. FIN 46R requires identification of the Company's participation in VIEs and consolidation of those VIEs of which the Company is the primary beneficiary. The Company adopted FIN 46 at December 31, 2003 and FIN 46R at March 31, 2004, and was not required to consolidate any existing interests pursuant to the requirements of FIN 46 or FIN 46R.

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("the Act"). The Act expanded Medicare to include, for the first time, coverage for prescription drugs, generally effective January 1, 2006. The Company provides health care, life insurance, prescription drug and other benefits to retired employees who meet certain age and years of service requirements. The Company elected to defer recognition of any impact under FSP 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003."

On May 19, 2004, the FASB issued FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," which requires employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Act.

Pending the release of final regulations, the Company was unable to conclude whether the benefits provided by the plan were actuarially equivalent to Medicare Part D under the Act, and to accurately measure the effect of the change on the accumulated postretirement benefit obligation ("APBO") or the net periodic postretirement benefit cost ("net periodic cost"). This was a result of uncertainty with treatment under the Act of contributions made by certain retirees and the Company's cap on employer medical premiums. Regulations and their interpretations were finalized in January 2004, and the reduction in APBO at December 31, 2004, was determined to be approximately $3.5 million. The expected subsidy will impact annual net periodic cost in 2005 and beyond.

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs" ("SFAS 151"), which clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material. SFAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not believe the adoption of SFAS 151 will have a material effect on its respective financial statements.

In December 2004, the FASB issued a revision to SFAS No. 123R, "Share-Based

Payments," which replaces SFAS No. 123, "Accounting for Stock-Based Compensation." The revision determines how the Company will measure the cost of employee services received in exchange for share-based payments. The cost of share-based payments will be based on the grant date fair value of the award. The guidance is effective as of the beginning of the first interim or annual reporting period after June 15, 2005. The Company has not yet determined what the impact of this new standard will be on its financial position or results of operations.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, as amended of APB Opinion No. 29" ("SFAS 153"), which addresses the measurement of exchanges of nonmonetary assets and redefines the scope of transactions that should be measured based on the fair value of the assets exchanged. SFAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not believe the adoption of SFAS 153 will have a material effect on its respective financial statements.

In December 2004, the FASB issued FASB Staff Position 109-1 ("FSP 109-1"), which was effective upon issuance, to provide guidance of the application of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), to the provision within the American Jobs Creation Act of 2004 ("Jobs Act") that provides a tax deduction on qualified production activities. The Jobs Act includes a tax deduction of up to 9 percent (when fully phased-in) of the lesser of (a) "qualified production activities income," as defined in the Jobs Act, or (b) taxable income (after the deduction for the utilization of any net operating loss carryforwards). The tax deduction is limited to 50 percent of W-2 wages paid by the taxpayer. FSP 109-1 clarifies that the manufacturer's deduction provided for under the Jobs Act should be accounted for as a special deduction in accordance with SFAS 109 and not as a tax rate reduction. The adoption of FSB 109-1 had no impact on the Company's financial statements. The Company is evaluating the effect that the manufacturer's deduction will have in subsequent years.

B. INVESTMENTS IN ASSOCIATED COMPANIES

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

	PERCENT OWNERSHIP AT DECEMBER 31, 2004	PERCENT OWNERSHIP AT DECEMBER 31, 2003	INVESTMENT IN EQUITY AT DECEMBER 31, 2004	INVESTMENT IN EQUITY AT DECEMBER 31, 2003
(IN THOUSANDS)				
VELCO-common.	29.17%	28.41%	$7,041	$2,469
VELCO-preferred	30.00%	30.00%	158	246
Total VELCO			7,199	2,715
VYNPC- Common	33.60%	33.60%	1,612	1,605
New England Hydro Transmission-Common . .	3.18%	3.18%	515	592
New England Hydro Transmission Electric-Common.	3.18%	3.18%	853	984
Total investment in associated companies.			$10,179	$5,896

VELCO. VELCO and its wholly-owned subsidiary, Vermont Electric Transmission Company, own and operate transmission systems in Vermont over which bulk power is delivered to all electric utilities in the state. VELCO operates under the terms of the 1985 Four-Party Agreement (as amended) with the Company and two other major distribution companies in Vermont.

VELCO has entered into transmission agreements with the State of Vermont and other electric utilities including the Company, 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 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 required to pay for its share of VELCO's operating costs including debt service costs. The Company plans to make capital investments of up to $20 million in VELCO through 2007 in support of various transmission projects, including a $4.6 million investment made in the last quarter of 2004.

Summarized unaudited financial information for VELCO is as follows:

At and for the years ended December 31,

(In thousands)	2004	2003	2002
Net income.	$ 1,683	$ 1,270	$ 1,094
Company's equity in net income.	$ 472	$ 418	$ 319
Total assets.	$145,632	$126,793	$106,613
Liabilities and long-term debt.	120,983	117,393	97,417
Net assets.	$ 24,649	$ 9,400	$ 9,196
Company's equity in net assets.	$ 7,199	$ 2,715	$ 2,614
Amounts due from (to) VELCO . .	$ (4,068)	$ (4,190)	$ (5,550)

Included in VELCO's revenues shown above are transmission services to the Company (reflected as transmission expenses in the accompanying Consolidated Statements of Income) amounting to $12.3 million in 2004, $12.0 million in 2003 and $12.7 million in 2002, respectively.

VERMONT YANKEE NUCLEAR POWER CORPORATION ("VYNPC"). The Company's ownership share of VYNPC has increased from approximately 19.0 percent in 2002 to approximately 33.6 percent currently, due to VYNPC's purchase of certain minority shareholders' interests. The Company's entitlement to energy produced by the Vermont Yankee nuclear plant owned by ENVY remains at approximately 20 percent of plant production.

Summarized unaudited financial information for VYNPC is as follows:
At and for the years ended December 31,

(In thousands)	2004	2003*	2002
Earnings:			
Operating revenues	$167,399	$187,123	$175,722
Net income applicable to common stock.	538	2,536	9,454
Company's equity in net income	$ 181	$ 498	$ 1,745

Total assets	$151,542	$150,720	$201,426
Liabilities and long-term debt	146,747	145,946	150,413
Net Assets	$ 4,795	$ 4,774	$ 51,203
Company's equity in net assets	$ 1,612	$ 1,605	$ 9,721
Amounts due from (to) VYNPC.	$ (3,324)	$ (2,648)	$ (3,487)

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

On July 31, 2002, VYNPC announced that the sale of the Vermont Yankee nuclear power plant to ENVY had been completed. Since the Company no longer owns an interest in the Vermont Yankee nuclear plant, we are not responsible for the costs of decommissioning the plant, nor are we responsible for any plant repairs or maintenance costs during outages. See Note K for further information concerning our long-term power contract with VYNPC.

ENVY has announced that, under current operating parameters, it will exhaust the capacity of its existing nuclear waste storage pool in 2007 or 2008 and will need to store nuclear waste in so-called "dry fuel storage" facilities to be constructed on the site. Current Vermont law appears to require ENVY to obtain approval of the Vermont State legislature, in addition to VPSB approval, to construct and use such dry fuel storage facilities. If ENVY is unsuccessful in receiving favorable legislative action and/or regulatory approval, ENVY has announced that it would be required to shut down the Vermont Yankee plant. If the Vermont Yankee plant is shut down, we would have to acquire substitute baseload power resources, comprising approximately 35 percent of our estimated total power supply needs. At currently projected market prices, we estimate the annual incremental cost (in excess of the projected costs of power under our power supply contract for output from the Vermont Yankee facility) would be approximately $9 million annually. Recovery of those increased costs in rates would require a rate increase of approximately 5 percent.

In April 2004 ENVY reported that two short spent fuel rod segments were not in what ENVY believed to be their documented location in the spent fuel pool. After initial review and visual inspection of the spent fuel pool, ENVY did not locate the fuel rod segments. By letter dated May 5, 2004, ENVY notified VYNPC that based on the terms of the Purchase and Sale Agreement dated August 1, 2001, and facts at that time, it was ENVY's view that costs associated with the spent fuel rod segment inspection effort were the responsibility of VYNPC. VYNPC responded that based on the information at that time, there was no basis for ENVY to claim the inspection was VYNPC's responsibility. Subsequently, ENVY's continuing documentation review led to the discovery of the fuel rod segments in a container in the spent fuel pool. We cannot predict the outcome of this matter at this time.

On June 18, 2004, a fire in the electrical conduits leading to a transformer outside the plant resulted in a shutdown of the ENVY plant. The outage ended on July 7, 2004. In response to the Company's request, the VPSB issued a final accounting order allowing the Company to defer its incremental replacement power costs during the outage totaling approximately $500,000. The order also instructs the Company to apply any proceeds received under a Ratepayer Protection Proposal ("RPP") to reduce the balance of deferred replacement power costs.

The RPP was a part of ENVY's request to uprate or increase the output of the VY nuclear plant that was approved by the VPSB. Under the RPP, we have indemnification rights to between approximately $550,000 and $1.6 million to recover uprate-related reductions in output for the three-year period beginning in May 2004 and ending after completion of the uprate (or a maximum of three years), depending on future wholesale energy market prices. ENVY disputes that the fire was uprate-related. The Company has petitioned the VPSB to resolve the dispute.

C. COMMON STOCK EQUITY AND STOCK AWARD PLANS

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 416,328 shares were reserved and unissued at December 31, 2004. The Company also funds an Employee Savings and Investment Plan ("ESIP") under which the Company may contribute shares of common stock.

During 2000, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established a stock incentive plan (the "2000 Stock Plan"). Under this plan, up to 500,000 shares of common stock may be issued in the form of options, stock grants, stock appreciation rights, restricted stock, restricted stock units, performance awards and other stock-based awards to any employee, officer, consultant, contractor or director providing services to the Company, or its subsidiaries. The Company has issued stock options, stock awards and deferred stock units to employees and directors under the plan. Outstanding options become exercisable at between one and four years after the grant date and remain exercisable until 10 years from the grant date. As of December 31, 2004, 23,023 shares are unissued under the 2000 Stock Plan.

During 2004, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established the 2004 Stock Incentive Plan, under which 225,000 shares in the form of stock grants, options, stock appreciation rights, restricted stock and restricted stock units, performance awards or other stock-based awards can be granted to any employee, officer, consultant, contractor or director providing services to the Company, or its subsidiaries. As of December 31, 2004, no shares have been issued under the 2004 Stock Incentive Plan.

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, and no options were granted in 2004. Options have been issued only to employees and directors.

The fair values of options granted in 2003, and 2002 are $1.33 and $2.27 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, 2004:

			Assumptions used in option pricing model				
Plan year	Weighted average exercise price	Outstanding options	Remaining Contractual Life	Risk Free Interest rate	Expected Life in Years	Expected Stock Volatility	Dividend Yield

2000	$ 7.90	145,600	5.6 years	6.05%	5	30.58	4.5%
2001	$16.77	18,100	6.6 years	5.25%	6	32.69	4.0%
2002	$17.90	49,300	7.6 years	4.50%	6.5	16.89	4.5%
2003	$20.64	2,300	8.3 years	2.48%	6	13.68	4.5%
Total	$11.07	215,300					

	Total Options	Weighted Average Price	Range of Exercise Prices	Options Exercisable
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
Granted.	-	-	-	
Exercised.	84,150	12.11	$ 7.90-$20.96	
Forfeited.	1,400	18.65	$17.54-$20.96	
Outstanding at December 31, 2004	215,300	$11.07	$ 7.90-$22.62	213,500

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		
	2004	2003	2002
	(in thousands)		
Net income before preferred dividends .	$ 11,584	$10,407	$11,494
Preferred stock dividend requirement. .	-	3	96
Net income applicable to common stock.	$ 11,584	$10,404	$11,398
Average number of common shares-basic .	5,083	4,980	5,592
Dilutive effect of stock options. . . .	171	160	164
Average number of common shares-diluted	5,254	5,140	5,756

As part of our long-term stock incentive program, unrestricted stock grants and deferred stock unit grants have been made to employees, senior management and directors. Unrestricted stock grants are recognized as compensation expense based on the fair value of the awards at the grant date. Deferred stock units are recognized as deferred compensation based on the fair value of the award at the grant date and charged to expense over the required service period for each award. Awards to senior management vest over a two year service period. Total compensation expense from all stock awards to directors, employees and senior management totaled $1.2 million in 2004 and $422,000 in 2003.

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.

Appropriated Retained Earnings. The Company had appropriated retained earnings of $353,000 and $277,000 at December 31, 2004 and 2003, respectively, relating to regulatory requirements arising from ownership of hydro-electric facilities.

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 Amended and Restated Articles of Incorporation. Under the most restrictive of such provisions, approximately $28.6 million of retained earnings were free of restrictions at December 31, 2004.

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 $300,000 of the 7.0 percent Class C preferred stock outstanding. During November 2002, the Company repurchased the remaining $200,000 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 $30.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by Sovereign Bank ("Sovereign"), expiring June 2005 (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 $3.0 million outstanding at a weighted average rate of 5.25 percent, and $500,000 outstanding at a weighted average rate of 4 percent, under the Fleet-Sovereign Agreement at December 31, 2004 and 2003, respectively. There was no non-utility short-term debt outstanding at December 31, 2004 or 2003.

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, 2004.

F. LONG-TERM DEBT

Substantially all of the property and franchises of the Company are subject to the lien of the indenture under which first mortgage bonds have been issued. The weighted average rate on long-term borrowings outstanding was 7.0 percent for both December 31, 2004 and 2003. The annual sinking fund requirements (excluding amounts that may be satisfied by property additions) are included in the following table with interest rates and maturities as of December 31 for the years presented.

LONG-TERM DEBT

FIRST MORTGAGE BONDS	(In thousands)		
Interest rate-Maturity	Annual Sinking Fund	2004	2003
7.05%-Dec. 15, 2006.	-	$ 4,000	$ 4,000
7.18%-Nov. 6, 2006	-	10,000	10,000
6.04%-Dec. 1, 2017	6,000,000 begins 2011	42,000	42,000
6.7%-Nov. 1, 2018.	-	15,000	15,000
9.64%-Sept. 1, 2020.	-	9,000	9,000
8.65%-Mar. 1, 2022	$ 500,000 begins 2012	13,000	13,000
Total Long-term Debt Outstanding		93,000	93,000
Less Current Maturities (due within one year).		-	-
TOTAL LONG-TERM DEBT, LESS CURRENT MATURITIES.	$	93,000	$93,000

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.

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 temporary differences, which gave rise to the net deferred tax liability at December 31, 2004 and December 31, 2003, were as follows:

	AT DECEMBER 31, 2004	2003
(In thousands)		
DEFERRED TAX ASSETS		
Contributions in aid of construction.	$ 2,155	$ 896
Deferred compensation and postretirement benefits.	4,972	4,303
Self insurance and other reserves . .	639	637
Other	1,654	2,602
	$ 9,420	$ 8,438
DEFERRED TAX LIABILITIES		
Property related.	$32,453	$29,230

Demand side management.	2,955	2,558
Deferred purchased power costs. . . .	1,033	792
Pine Street reserve	2,753	2,410
Other	2,449	3,448
	$41,643	$38,438
Net accumulated deferred income tax liability	$32,223	$30,000

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

	YEARS ENDED DECEMBER 31, 2004	2003	2002
(In thousands)			
Net change in deferred income tax . . liability	$2,223	$ 3,529	$ 2,712
Change in income tax related regulatory assets and liabilities .	2,151	(2,166)	2,759
Change in tax effect of accumulated other comprehensive income.	(391)	398	(1,612)
Deferred income tax expense (benefit)	$3,983	$ 1,761	$ 3,859

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

	YEARS ENDED DECEMBER 31, 2004	2003	2002
(In thousands)			
Current federal income taxes .	$ 461	$2,434	$1,873
Current state income taxes . .	1,602	1,207	593
Total current income taxes . .	2,063	3,641	2,466
Deferred federal income taxes.	3,843	1,307	2,920
Deferred state income taxes. .	140	454	939
Total deferred income taxes. .	3,983	1,761	3,859
Investment tax credits-net . .	(284)	(282)	(282)
Income tax expense	$5,762	$5,120	$6,043

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

(In thousands)	2004	2003	2002
	YEARS ENDED DECEMBER 31,		
Income before income taxes and preferred dividends	$17,346	$15,527	$17,537
Federal statutory rate	35.0%	34.0%	34.0%
Computed "expected" federal income taxes	$ 6,071	$ 5,279	$ 5,963
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation basis difference.	(149)	41	41
Dividends received credit	(452)	(465)	(575)
Amortization of ITC	(284)	(282)	(282)
State tax	1,133	1,082	1,011
Excess deferred taxes	(123)	(60)	(60)
Wind energy production credit	(125)	(130)	-
Other	(309)	(345)	(55)
Total federal and state income tax	$ 5,762	$ 5,120	$ 6,043
Effective combined federal and state income tax rate	33.2%	33.0%	34.5%

H. PENSION AND RETIREMENT PLANS.

The Company has a qualified non-contributory defined benefit pension plan (the "Pension Plan") covering substantially all of its employees. The retirement benefits are based on the employees' level of compensation and length of service. Under the terms of the Pension Plan, employees are vested after completing five years of service, and can retire when they reach age 55 with a minimum of 10 years of service. 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 and postretirement health care 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 the Pension Benefit Guaranty Corporation, and so long as the Company's liquidity needs do not preclude such investments. The Company made voluntary defined benefit plan contributions totaling $3.5 million during 2003 and $2.25 million during 2004. The Company currently plans to contribute between $2.0 and $3.0 million of additional funds during 2005.

During 2002, the Company's retirement plan asset return experience required the Company to recognize a minimum pension liability of $4.0 million, and $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.

During 2004, the Company increased its previously recognized minimum pension liability by $1 million to approximately $4 million, primarily as a result of a decrease in the pension plan discount rate. Common equity decreased approximately $566,000, net of applicable income tax, through a charge to 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, 2004 and 2003.

	At and for the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
(In thousands)				
Change in projected benefit obligation:				
Projected benefit obligation prior year end . .	$33,980	$29,937	$21,906	$ 20,707
Service cost.	991	755	335	496
Interest cost	2,005	1,900	1,165	1,316
Participant contributions	-	-	115	136
Plan change	-	292	-	(1,812)
Change in actuarial assumptions	-	-	-	-
Actuarial (gain) loss	1,225	2,789	(3,595)	2,070
Benefits paid	(1,614)	(1,629)	(947)	(1,007)
Administrative expense.	(74)	(64)	-	-
Projected benefit obligation as of year end . .	$36,513	$33,980	$18,979	$ 21,906
Accumulated benefit obligation.	$33,032	$30,459	$18,979	$ 21,906
Change in plan assets:				
Fair value of plan assets as of prior year end.	$27,867	$21,104	$10,229	$ 8,760
Administrative expenses paid.	(74)	(64)	-	-
Participant contributions	-	-	-	-
Employer contributions.	1,550	3,500	700	-
Actual return on plan assets.	2,201	4,956	852	1,558
Benefits paid	(1,614)	(1,629)	(110)	(89)
Fair value of plan assets as of year end. . . .	$29,930	$27,867	$11,671	$ 10,229
Funded status as of year end.	$(6,584)	$(6,113)	$(7,307)	$(11,677)
Unrecognized transition obligation.	-	-	2,624	2,952
Unrecognized prior service cost	815	984	(1,977)	(2,216)
Unrecognized net actuarial loss	7,438	6,372	5,322	9,250
Prepaid (accrued) benefits at year end.	$ 1,669	$ 1,243	$(1,338)	$ (1,691)

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31, 2004, 2003 and 2002 were $475,000, $392,000 and $408,000, respectively, under this plan. This plan is funded in part through insurance contracts.

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

	For the years ended December 31,					
	Pension Benefits			Other Postretirement Benef		
(In thousands)	2004	2003	2002	2004	2003	2002
Service cost	$ 991	$ 755	$ 668	$ 335	$ 496	$ 29
Interest cost.	2,005	1,900	1,849	1,165	1,316	1,11
Expected return on plan assets	(2,285)	(1,851)	(2,112)	(857)	(740)	(85
Amortization of transition asset	-	(77)	(164)	-	-	
Amortization of prior service cost	169	147	147	(239)	(58)	(5
Amortization of the transition obligation.	-	-	-	328	328	32
Recognized net actuarial gain.	243	294	-	338	381	6
Net periodic benefit cost.	$ 1,123	$ 1,168	$ 388	$1,070	$1,723	$ 89

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 Benefi	
	2004	2003	2004	2003
Weighted average assumptions as of year end:				
Discount rate.	5.75%	6.00%	5.75%	6.00%
Expected return on plan assets	8.25%	8.50%	8.25%	8.50%
Rate of compensation increase.	4.00%	4.25%	4.00%	4.25%
Medical inflation.	-	-	10.75%	9.25%
Measurement date	12/31/2004	12/31/2003	12/31/2004	12/31/2003
Census date.	1/1/2004	1/1/2003	1/1/2004	1/1/2003

Assumptions used in periodic cost measurement	For the years ended December 31,			
	Pension benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Weighted average assumptions as of year end:				
Discount rate.	6.00%	6.50%	6.00%	6.50%
Expected return on plan assets	8.25%	8.50%	8.25%	8.50%
Rate of compensation increase.	4.25%	4.25%	4.25%	4.25%
Current year trend	-	-	9.25%	10.00%
Ultimate year trend.			5.50%	5.50%
Year of ultimate trend			2009	2009

For measurement purposes, a 10.75 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2004. This rate of increase gradually declines to 5.0 percent in 2011. 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, 2004 by 12.0 percent or $2.3 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2004 by $190,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2004 by 9.3 percent or $1.8 million, and the total of the service and interest cost components of net periodic postretirement cost for 2004 by $156,000.

The Company's defined benefit plan investment policy seeks to achieve sufficient growth to enable the defined benefit plans to meet their 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.

Weighted Average Asset Allocation

Asset Category	Pension Assets			Other Postretirement Benefit Assets		
	For the years ended December 31,					
	2005 TARGET	2004*	2003	2005 TARGET	2004	2003
Equity Securities . . .	65.00%	48.96%	63.10%	65.00%	63.00%	62.00%
Debt Securities	30.00%	25.80%	24.92%	35.00%	32.00%	36.00%
Real Estate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other	0.00%	19.94%	6.60%	0.00%	5.00%	2.00%
Alternative investments	5.00%	5.30%	5.38%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

*The large difference between the target and actual allocations is due to a $5 million cash transfer between funds at December 31, 2004

	Pension benefits		Other Postretirement Benefits	
	Contributions	Projected Benefit payments	Contributions	Projected Benefit payments
	In Thousands			

2005.	$ 1,500	$ 1,623	$ 1,362	$ 962
2006.	1,500	1,639	1,000	885
2007.	1,500	1,657	1,000	942
2008.	1,500	1,736	1,000	978
2009.	1,500	1,796	1,000	1,001
2010 through 2014	7,500	10,362	5,000	5,580

I. COMMITMENTS AND CONTINGENCIES

Other contingencies are discussed under Note A, Regulatory Accounting and Major Customers and Other Concentration Risks and Note B, Vermont Yankee Nuclear Power Corporation ("VYNPC") and Note K Long-Term Power Purchases.

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. There are no current legislative or regulatory initiatives pending or anticipated in Vermont to pursue deregulation. 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 would 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.

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. We have estimated total future costs of the Company's future obligations under the consent decree to be approximately $6.5 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 $13.3 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 is expected to 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.

JOINTLY-OWNED FACILITIES

The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2004, as follows:

	Ownership Interest	Share of Capacity	Share of Utility Plant	Share of Accumulated Depreciation
	(In %)	(In MW)	(In thousands)	
Highgate	33.8	67.6	$ 10,296	$ 5,196
McNeil	11.0	5.9	9,109	5,665
Stony Brook (No. 1). . .	8.8	31.0	10,377	9,408
Wyman (No. 4).	1.1	6.8	1,980	1,443
Metallic Neutral Return.	59.4	-	1,563	867

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

The Company's share of expenses for these facilities is reflected in Operating Expenses in the Consolidated Statements of Income under Company-owned generation for the three listed generation plants and under Transmission for the Metallic Neutral Return and Highgate facilities. Each participant in these facilities must provide its own financing.

RATE MATTERS

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

The Company's rates remained 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. We submitted a cost of service schedule supporting the 1.9 percent rate increase for 2005 in accordance with the plan. That increase became effective on January 1, 2005 in accordance with the plan. If the Company's cost of service filing in 2006 establishes that a rate increase of less than 0.9 percent is required for the Company to meet its revenue requirement, including an allowed return on equity of 10.5 percent, the Company will implement the lesser rate increase. The VPSB retains the discretion to open an investigation of the Company's rates at any time, at the request of the DPS, the request of ratepayers, or on its own volition. Certain ratepayers requested the VPSB to open such an investigation in connection with the Company's 1.9 percent rate increase for 2005. The VPSB granted the request in December 2004, and then, at our request, closed and terminated its investigation in January 2005, with no adverse impact on the Company's rates.

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

The Company's allowed return on equity is 10.5 percent for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on utility operations are capped at 10.5 percent. The Company did not experience excess earnings in 2004. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to recover regulatory assets, as the Department directs.

The Company carried 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 were applied in 2004 to offset increased costs.

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 filed with the VPSB in 2004 a new fully allocated cost of service study and rate re-design, which allocates the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design is 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 was restricted until new rates went into effect, which occurred in January 2005. Although this restriction has expired, we have no plans to make material investments in non-utility operations.

COMPETITION

The Town of Rockingham, Vermont, located in the southeastern portion of our service territory, has exercised an option to purchase a hydro-electric facility partially located in the town (the "Bellows Falls facility"). If Rockingham, or its assignee, is successful in arranging for purchase of the Bellows Falls facility, we expect to conclude an agreement to permit Rockingham to be responsible for its own power supply needs, with the Company providing distribution and other services to the town's electric department. In any such agreement the Company would continue to own its distribution plant located in the town and receive distribution services revenues sufficient to cover all costs of providing services and all stranded costs associated with the Company's present obligation to provide integrated electric service to customers in Rockingham. Such an agreement would require VPSB approval. The Company receives annual revenues of approximately $3 million from its customers in Rockingham.

OTHER REGULATORY MATTERS

Central Vermont Public Service Corporation ("CVPS") is currently subject to a rate investigation by the VPSB. In that proceeding, the DPS has advocated positions that, if adopted by the VPSB and applied to the Company, could adversely affect our cash flows and operating results. Areas of risk include:

* The Department's advocacy for an earnings cap calculation that would potentially subject all items on the balance sheet and income statement to a retroactive review in order to determine whether the Company has met or exceeded the earnings cap. Our 2003 Rate Plan provides that the Company operate under an earnings cap through 2006. The Company calculates its earnings under the cap in a manner that differs from the methodology advocated by the DPS in the CVPS rate proceeding.

* DPS advocacy for elimination or reduction of costs of future removal that are currently embedded in depreciation rates and reflected in our cash flows. The methodology we currently employ is consistent with that used in most other regulatory jurisdictions.

* DPS advocacy for reduced rates of return on equity for CVPS.

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 hydro-electric 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 received VPSB approval for, and has made additional dam improvements at the facility. The VPSB has pending a regulatory proceeding to determine whether to impose regulatory penalties in connection with the 1995 dam improvements.

J. OBLIGATIONS UNDER TRANSMISSION INTERCONNECTION SUPPORT AGREEMENT AND OTHER LEASES

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 provides 2,000 megawatts of capacity for transmission of Hydro Quebec power 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, 2004, the present value of the Company's obligation is approximately $4.2 million.

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

Years ending
December 31

(In thousands)

2005.	$ 383
2006.	383
2007.	383
2008.	383
2009.	383
Total for 2010-2015	2,299
Total	$ 4,216

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

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.

Purchased power expense by significant contract supplier for the Years ended December 31,

In thousands	2004	2003	2002
Hydro Quebec.	$48,309	$46,367	$47,914
Morgan Stanley. . . .	11,106	59,311	71,259
VYNPC	33,331	38,109	34,385
Small Power Producers	15,832	15,277	14,393
Stony Brook	1,696	2,222	1,766

Information, including estimates for the Company's portion of certain minimum costs, with regard to significant purchased power contracts of this type in effect during 2004 follow.

VERMONT YANKEE.

The Company has a long-term power purchase contract with VYNPC, 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, including costs to decommission the plant, 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 VYNPC sale of its nuclear power plant to ENVY also calls for ENVY, through its power contract with VYNPC, 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 ("PPA"), including projected charges for the years indicated, follows:

(Dollars in thousands except per KWh)	VYNPC Contract	
Capacity acquired	106 MW	
Contract period expires	2012	
Company's share of output	20%	
Annual energy charge.	2004	$32,838
estimated	2005-2012	$31,949
Average cost per KWh.	2004	$ 0.044
estimated	2005-2012	$ 0.041

Prices under the PPA range from $39 to $45 per megawatt hour. The PPA contains a provision known as the "low market adjuster," which calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts beginning November 2005. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price.

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 its share of the Vermont Yankee power plant sale proceeds, approximately $8.2 million, during October 2003, and used the proceeds to retire debt.

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 "VJO 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 VJO Contract participant fails to meet its obligation under the VJO Contract with Hydro Quebec, the remaining contract participants, including the Company, will step-up to the defaulting participant's share on a prorated basis.

In accordance with guidance set forth in FIN 45, the Company is required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood of triggering the guarantee is remote. In regards to the "step-up" provision in the VJO Contract, the Company must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. The Company believes this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power. Despite the remote chance that such an event could occur, the Company estimates that its undiscounted purchase obligation would be approximately $880 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2005 and remained in default for the duration of the contract. In such a scenario, the Company would then own the power and could seek to recover its costs from the defaulting members, its retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

Hydro Quebec also has the right to reduce the load factor from 75 percent to 65 percent under the VJO Contract a total of three times over the life of the contract. The Company can delay such reduction by one year under the VJO 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 net cost of Hydro Quebec's exercise of its option increased power supply expense during 2003 by approximately $4.5 million.

During 2003, Hydro Quebec exercised its second option to reduce the load factor for 2004 at an incremental expense of approximately $1.8 million. Hydro Quebec exercised its third option in 2004 for deliveries occurring principally during 2005 that we estimate will result in an incremental expense of $1.8 million based on current market prices that could change by a material amount. 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 VJO 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.

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, and there are no generation plant outage risks, though there are outage risks related to the operation of the transmission system.

A summary of the Hydro Quebec contracts, including historic and projected charges for the years indicated, follows:

	THE VJO CONTRACT				
	SCHEDULE B			SCHEDULE	
	(Dollars in thousands except per KWh)				
Capacity acquired. . . .	68 MW				46
Contract period.	1995-2015				1995-20
Minimum energy purchase. (annual load factor)	65%-75%				65%-
Annual energy charge . .	2004	$	9,868		$ 6,812
estimated.	2005-2015	$	13,756	(1)	$ 9,400
Annual capacity charge .	2004	$	16,813		$11,613
estimated.	2005-2015	$	17,121	(1)	$11,699
Average cost per KWh . .	2004	$	0.073		$ 0.076
estimated.	2005-2015	$	0.064	(2)	$ 0.064

(1) Estimated average includes load factor reduction to 65 percent in 2005.
(2) Estimated average in nominal dollars levelized over the period indicated includes amortization of payments to Hydro Quebec.

Under a separate arrangement established in 1996 (the "9701 agreement"), 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 VJO Contract. The cumulative amount of energy purchased under the 9701 agreement shall not exceed 950,000 MWh. Hydro Quebec's option to curtail energy deliveries pursuant to the VJO 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 VJO 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, 2004, Hydro Quebec had purchased or called to purchase 566,000 MWh under option B.

The Company believes that it is probable that Hydro Quebec will call options A and B for 2005, and has purchased replacement power for approximately half of the expected call at an incremental cost of $1.1 million.

In 2004, Hydro Quebec exercised option A and option B, and called for deliveries to third parties at a net expense to the Company of approximately $3.2 million, including capacity charges.

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.

MORGAN STANLEY CONTRACT.

In February 1999, the Company entered into a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"). In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006. The Morgan Stanley Contract price is substantially below current market prices. The Morgan Stanley Contract currently supplies approximately 16 percent of the Company's estimated customer demand ("load").

Under the Morgan Stanley Contract, on a daily basis, and at Morgan Stanley's discretion, we sell power to Morgan Stanley from part of our portfolio of power resources at predefined operating and pricing parameters. Morgan Stanley sells to the Company, at a predefined price, power sufficient to serve pre-established load requirements. We remain responsible for resource performance and availability. The Morgan Stanley Contract provides no coverage against major unscheduled power supply outages. Beginning January 1, 2004, the Company reduced the power that it sells pursuant to the Morgan Stanley Contract. The output of some of our power-supply resources, including purchases pursuant to our Hydro Quebec and VYNPC contracts, which were sold to Morgan Stanley through 2003, are no longer included in the Morgan Stanley Contract. This reduction in sales to Morgan Stanley reduced wholesale revenues by approximately $56.2 million during 2004 when compared with 2003, and correspondingly reduced power supply expense by a similar amount. This change did not adversely affect the Company's operating results or its opportunity to earn its allowed rate of return during 2004.

The Company purchased or expects to purchase the following amounts from Morgan Stanley for the years indicated:

	The Morgan Stanley Contract
Capacity acquired*. . .	1-182 MW
Contract period expires	2006
Annual energy charge :.	
2004	$11.1 million
2005 estimate	$12.6 million
2006 estimate	$10.2 million

*Capacity ranges between 0 and 182 MW over the remaining contract life depending on the scheduled hour.

Beginning January 1, 2004, the Company reduced the power that it sells to Morgan Stanley under the contract. The reduction in sales lowered wholesale revenues by approximately $56 million, and power supply expense by a similar amount. The change did not adversely affect the Company's opportunity to earn its allowed rate of return during 2004.

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

UNIT PURCHASES.

Under a long-term contract with Massachusetts Municipal Wholesale Electric Company ("MMWEC"), the Company is purchasing a percentage of the electrical output of the Stony Brook production plant constructed by MMWEC. The contract obligates 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 plant is operating, for the life of the unit. The cost of power obtained under this long-term contract, including payments required when the 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 this purchased power contract in effect during 2004 follows:

	STONY BROOK
	(Dollars in thousands)
Plant capacity.	352.0 MW
Company's share of output	4.40%
Company's annual share of:	
Interest.	$ 107
Other debt service.	466
Other capacity.	537
Total annual capacity	$ 1,110
Company's share of long-term debt	$ 1,304

INDEPENDENT POWER PRODUCERS.

The Company receives power from several independent power producers

("IPPs"). These plants use water, biomass and trash as fuel. Most of the power comes through a state-appointed purchasing agent, Vermont Electric Power Producers Inc. ("VEPPI"), which assigns power to all Vermont utilities under VPSB rules. In 2004, the Company received 124,617 MWh under these long-term contracts at a cost of $15.8 million. These IPP purchases amount to 6.0 percent of the Company's total MWh purchased and 11.5 percent of purchase power expenses. Estimated purchases from IPPs are expected to be $15.9 million in 2005, $16.5 million in 2006, $17.4 million in 2007, $17.3 million in 2008 and $15.5 million in 2009.

L. 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.

Amounts in thousands except per share data	2004 Quarter ended				
	MARCH	JUNE	SEPTEMBER	DECEMBER	TOT
Operating revenues.	$63,123	$54,585	$ 54,926	$ 56,182	$228
Operating income.	5,019	2,776	4,595	3,088	15
Net income-continuing operations.	$ 3,740	$ 1,783	$ 3,392	$ 2,144	$ 11
Net income-discontinued operations.	(6)	(1)	(2)	534	
Net Income applicable to common stock	$ 3,734	$ 1,782	$ 3,390	$ 2,678	$ 11
Basic earnings per share from:					
Continuing operations	$ 0.74	$ 0.35	$ 0.67	$ 0.42	$
Discontinued operations	-	-	-	0.10	
Basic earnings per share.	$ 0.74	$ 0.35	$ 0.67	$ 0.52	$
Weighted average common shares outstanding. .	5,046	5,072	5,089	5,124	5
Diluted earnings per share from:					
Continuing operations	$ 0.72	$ 0.34	$ 0.65	$ 0.39	$
Discontinued operations	-	-	-	0.10	
Diluted earnings per share.	$ 0.72	$ 0.34	$ 0.65	$ 0.49	$
Weighted average common and common equivalent shares outstanding	5,205	5,228	5,251	5,282	5

	2003 Quarter ended				
	MARCH	JUNE	SEPTEMBER	DECEMBER	TOTAL
Operating revenues.	$72,945	$64,455	$ 71,975	$ 71,095	$280,47
Operating income.	5,231	2,425	4,302	3,348	15,30
Net income-continuing operations.	$ 4,084	$ 1,120	$ 3,034	$ 2,087	$ 10,32
Net income-discontinued operations.	(13)	(8)	6	94	7
Net Income applicable to common stock	$ 4,071	$ 1,112	$ 3,040	$ 2,181	$ 10,40
Basic earnings per share from:					
Continuing operations	$ 0.82	$ 0.22	$ 0.61	$ 0.43	$ 2.0
Discontinued operations	-	-	-	0.01	0.0
Basic earnings per share.	$ 0.82	$ 0.22	$ 0.61	$ 0.44	$ 2.0

Weighted average common shares outstanding. .	4,959	4,969	4,982	5,009	4,98
Diluted earnings per share from:					
Continuing operations	$ 0.80	$ 0.22	$ 0.59	$ 0.40	$ 2.0
Discontinued operations	-	-	-	0.01	0.0
Diluted earnings per share.	$ 0.80	$ 0.22	$ 0.59	$ 0.41	$ 2.0
Weighted average common and common equivalent shares outstanding	5,118	5,129	5,141	5,165	5,14

	2002 Quarter ended				
	MARCH	JUNE	SEPTEMBER	DECEMBER	TOTAL
Operating revenues.	$68,866	$65,135	$ 73,477	$ 67,130	$274,608
Operating income.	4,441	2,814	3,745	4,080	15,080
Net income-continuing operations.	$ 3,354	$ 1,875	$ 3,042	$ 3,028	$ 11,299
Net income-discontinued operations.	-	-	-	99	99
Net Income applicable to common stock	$ 3,354	$ 1,875	$ 3,042	$ 3,127	$ 11,398
Basic earnings per share from:					
Continuing operations	$ 0.59	$ 0.33	$ 0.53	$ 0.57	$ 2.02
Discontinued operations	-	-	-	0.02	0.02
Basic earnings per share.	$ 0.59	$ 0.33	$ 0.53	$ 0.59	$ 2.04
Weighted average common shares outstanding. .	5,691	5,711	5,723	5,333	5,756
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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Green Mountain Power Corporation

We have audited the accompanying consolidated balance sheets of Green Mountain Power Corporation and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (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, such consolidated financial statements present fairly, in all material respects, the financial position of Green Mountain Power Corporation and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 21, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an adverse opinion on the effectiveness of the Company's internal control over financial reporting because of a material weakness.

DELOITTE & TOUCHE LLP
Boston, Massachusetts
March 21, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Green Mountain Power Corporation

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Green Mountain Power Corporation and subsidiaries (the "Company") did not maintain effective internal control over financial reporting as of December 31, 2004, because of the effect of the material weakness identified in management's assessment based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management's assessment: Deficiencies existed in both the design and operating effectiveness of controls associated with the Company's accounting for income taxes. These deficiencies include a failure to timely reconcile account balances including the preparation of a tax balance sheet, incorrect accounting for tax accounts related to the contributions in advance of construction, certain tax credits and non-regulated tax accounts, and insufficient dedication of resources to the preparation, supervision and review of tax accounting. The deficiencies resulted in an immaterial adjustment to properly present the financial statements in accordance with generally accepted accounting principles. The deficiencies were concluded to represent a material weakness in the aggregate due to the potential for additional misstatements and the lack of mitigating controls to detect the misstatements. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2004, of the Company and this report does not affect our report on such financial statements.

In our opinion, management's assessment that the Company did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004, of the Company and our report dated March 21, 2005 expressed an unqualified opinion on those financial statements.

DELOITTE & TOUCHE LLP
Boston, Massacusetts
March 21, 2005

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, we carried out an evaluation, with the participation of our management, including our chief executive officer and chief 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 chief executive officer and chief financial officer concluded that our disclosure controls and procedures were not effective as of such date because we identified a material weakness in our internal control over financial reporting in our accounting for income taxes, as described below. Due to this material weakness, in preparing our financial statements at and for the year ended December 31, 2004, we performed additional procedures relating to our accounting for income taxes to ensure that such financial statements were stated fairly in all material respects in accordance with generally accepted accounting principles in the United States.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment under the criteria for effective internal control over financial reporting described in "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission, management determined that as of December 31, 2004, we did not maintain effective internal control over financial reporting, due to a material weakness as a result of deficiencies in both the design and operating effectiveness of controls associated with our accounting for income taxes. These deficiencies include a failure to timely reconcile account balances including the preparation of a tax balance sheet, incorrect accounting for tax accounts related to the contributions in advance of construction, certain tax credits and non-regulated tax accounts, and insufficient dedication of resources for the preparation, supervision and review of tax accounting. The material weakness identified by management resulted in an immaterial reclassification of certain deferred tax liabilities to other deferred credit accounts on the Company's balance sheet as of December 31, 2003. These deficiencies were concluded to represent a material weakness due to the potential for additional misstatements and the lack of other mitigating controls to detect the misstatements.

Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Management's Remediation Plans

In addition to the required use of a tax balance sheet in accordance with FAS 109, we intend to take the following actions to improve and remediate the material weakness in our internal control over financial reporting:

We will implement additional and enhanced internal reviews in the tax area, including tax rate reconciliations, commencing in the first quarter of 2005.

We will retain and implement an additional review by outside experts on tax accounting, including regulatory tax items, on a periodic basis commencing in the first quarter of 2005.

We will implement new tax accounting software to improve controls over complex spreadsheet models during the latter half of 2005.

We believe these actions will strengthen our internal control over financial reporting and address the material weakness identified by management. Our management has committed what it believes to be sufficient resources to this remediation plan, but there can be no assurance that all control deficiencies will be remediated on a timely basis. The Audit Committee will monitor the progress of our remediation efforts.

Any failure to implement and maintain the improvements in the controls over our financial reporting, or difficulties encountered in the implementation of these improvements in our controls, could cause us not to meet our reporting obligations.

Changes in Internal Controls

We continue to review, revise and improve the effectiveness of our internal control over financial reporting, including strengthening our internal controls relating to accounting for income taxes as described above. Except as described above, we have made no significant change in our internal control over financial reporting in connection with our fourth quarter evaluation that would materially affect, or is reasonably likely to materially affect, our internal control over financial reporting.

PART III

ITEM 10

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 will be set forth under the captions "Election of Directors," "Nominees for Election to the Board of Directors," "Information About Our Board of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance," in the Company's definitive proxy statement relating to its annual meeting of stockholders to be held on May 23, 2005. 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 April 2005.

Because our common stock is listed on the New York Stock Exchange (the "NYSE"), our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of June 7, 2004. In addition, we have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our principal executive officer and principal financial officer required under Sections 906 and 302 of the Sarbanes Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

ITEMS 11, 12, 13 AND 14

The information called for by Items 11, 12, 13 and 14, "Executive Compensation," "Security Ownership of Certain Beneficial Owners and Management," "Certain Relationships and Related Transactions," and "Principal Accounting Fees and Services," will be set forth under the captions "Executive Compensation and Other Information," "Compensation Committee Report on Executive Compensation," "Pension Plan Information and Other Benefits," "Equity Compensation Plan

Information," "Securities Ownership of Certain Beneficial Owners and Management," and "Audit Committee Report" in the Company's definitive proxy statement relating to its annual meeting of stockholders to be held on May 23, 2005. 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 April 2005.

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

List of documents filed as part of this Form 10-K:

(1) Financial Statements. See the Index to the Company's financial statements set forth in Item 8 hereof.

(2) Financial Statement Schedules. N/A.

(3) Exhibits. See the Exhibit Index set forth at the end of this Form 10-K.

SIGNATURES

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

GREEN MOUNTAIN POWER CORPORATION

Date: March 28, 2005

By:/s/ Christopher L. Dutton______

Christopher L. Dutton, President and Chief Executive Officer

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

SIGNATURE	TITLE	DATE
/s/ Christopher L. Dutton_ Christopher L. Dutton	President, Chief Executive Officer, and Director	March 28, 2005
/s/ Mary G. Powell_______ Mary G. Powell	Chief Operating Officer, Senior Vice President	March 28, 2005
/s/ Robert J. Griffin Robert J. Griffin	Chief Financial Officer, Vice President and Treasurer	March 28, 2005
*Nordahl L. Brue)	Chairman of the Board	
*Elizabeth Bankowski)		
*William H. Bruett)		

*Merrill O. Burns)

*David R. Coates) Directors

*Kathleen C. Hoyt)

*Euclid A. Irving)

*Marc A. vanderHeyden)

*By: _/s/ Christopher L. Dutton March 28, 2005

Christopher L. Dutton
(Attorney - in - Fact)

ITEM 15(A)3 AND ITEM 15C. EXHIBITS SEC docket
incorporated
by reference
Exhibit or Page filed

Number	Description	Exhibit	he
3-1	Amended and Restated Articles of Incorporation dated. . . . . . . May 27, 2004.	3A	Form 1 June 2
3.b	By-laws of the Company, as amended February 10, 1997.	3.b	Form 1
3.c	By-laws of the Company, as amended December 8, 2003..	3	Form 8 200
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 April 1, 1961.	4.b.2	
4.b.3	Second Supplement 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 of August 1, 1976.. . . .	4.b.7	
4.b.8	Eighth Supplemental Indenture dated as of December 1, 1979. . . .	4.b.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 1
4.b.11	Eleventh Supplemental Indenture dated as of September 1, 1990.. .	4.b.11	Form 1 199
4.b.12	Twelfth Supplemental Indenture dated as of March 1, 1992.	4.b.12	Form 1
4.b.13	Thirteenth Supplemental Indenture dated as of March 1, 1992.. . .	4.b.13	Form 1
4.b.14	Fourteenth Supplemental Indenture dated as of November 1, 1993. .	4.b.14	Form 1
4.b.15	Fifteenth Supplemental Indenture dated as of November 1, 1993.. .	4.b.15	Form 1
4.b.16	Sixteenth Supplemental Indenture dated as of December 1, 1995.. .	4.b.16	Form 1
4.b.17	Revised form of Indenture as filed as an Exhibit to . . . . Registration Statement No. 33-59383.	4.b.17	Form 1 199
4.b.18	Credit Agreement by and among Green Mountain Power, The Bank. . .	4.b.18	Form 1

	of Nova Scotia, State Street Bank and Trust Company, Fleet National Bank, and Fleet National Bank, as Agent.		
4.b.18(a)	Amendment to Exhibit 4.b.18..	4.b.18(a)	Form 1 199
4.b.19	Seventeenth Supplemental Indenture dated as of December 1, 2002..	4.b.19	Form 1
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.d	
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 Funds Agreement . . . between the Company and Vermont Yankee Nuclear Power Corporation.	13.f	
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 19, 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.	10.b.9	
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 utilities for allocation of VELCO's rights and obligations as a participating New England utility in the trans- mission interconnection between New England and Hydro Quebec.	10.b.39	
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 interconnection 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 participating 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 Quebec 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 1
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 1

10.b.70	Firm Power and Energy Contract dated as of February 23, 1987, . . between the Vermont Joint Owners of the Highgate facilities and Hydro Quebec for up to 50 MW of capacity.	10.b.70	Form 1
10.b.70(a)	Amendment to 10.b.70.	10.b.70(a)	Form 1
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 1
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 1 June 1
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 1
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 1
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 1
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 1 June 1
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 1 June 1
10.b.85	Power Purchase and Sale Agreement between Morgan Stanley. . . . . Capital Group Inc. and the Company.	10.b.85	Form 1
10.b.90	Power Purchase Agreement between Entergy Nuclear Vermont. . . . . Yankee LLC and Vermont Yankee Nuclear Power Corporation.	10.b.90	Form 1 200
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.91	Form 1 200
10.b.92	Amendment to Power Purchase and Sale Agreement between Morgan . . Stanley Capital Group, Inc. and the Company.	10.b.92	Form 1
10.b.93	2001 Amendatory Agreement Power Supply Agreement between. . . . . the Company and Vermont Yankee Nuclear Power Corporation.	10.b.93	Form 1
10.b.94	Fourth Amended and Restated Credit Agreement by and among . . . . Green Mountain Power Corporation, Fleet National Bank, Sovereign Bank and Fleet National Bank as Agent dated June 16, 2004.	10.b.94	Form 1

Management contracts or compensatory plans or arrangements required

Exhibit Number	to be filed as exhibits to this Form 10-K pursuant to Item 14(c)., all under SEC Docket 1-8291	Exhibit	
10.d.1b	Green Mountain Power Corporation Second Amended and. . . . . Restated Deferred Compensation Plan for Directors.	10.d.1b	Form 10-K 199
10.d.1c	Green Mountain Power Corporation Second Amended and Restated Deferred Compensation Plan for Officers.	10.d.1c	Form 10-K 199
10.d.1d	Amendment No. 93.1 to the Amended and Restated Deferred. . . Compensation Plan for Officers.	10.d.1d	Form 10-K 199
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 199
10.d.4	Green Mountain Power Corporation Officers' Insurance Plan. .	10.d.4	Form 10-K 199
10.d.4a	Green Mountain Power Corporation Officers' Insurance . . . . Plan as amended.	10.d.4a	Form 10-K 199
10.d.8	Green Mountain Power Corporation Officers' Supplemental. . . Retirement Plan.	10.d.8	Form 10-K 199
10.d.15c	Green Mountain Power 2000 Stock Incentive Plan..	10.d.15c	Form 10-K 200
10.d.40	Severance Agreement with C. L. Dutton.	10.d.40	Form 10-K 200
10.d.41	Severance Agreement with D. J. Rendall, Jr..	10.d.41	Form 10-K 200
10.d.42	Severance Agreement with R. J. Griffin	10.d.42	Form 10-K 200
10.d.43	Severance Agreement with W. S. Oakes	10.d.43	Form 10-K 200
10.d.44	Severance Agreement with M. G. Powell.	10.d.44	Form 10-K 200
10.d.45	Severance Agreement with S. C. Terry	10.d.45	Form 10-K 200
10.d.46	Deferred Stock Unit Agreement with D. J. Rendall, Jr.. . . .	10.d.46	Form 10-K 200
10.d.47	Deferred Stock Unit Agreement with C. L. Dutton.	10.d.47	Form 10-K 200
10.d.48	Deferred Stock Unit Agreement with S. C. Terry	10.d.48	Form 10-K 200
10.d.49	Deferred Stock Unit Agreement with R. J. Griffin	10.d.49	Form 10-K 200
10.d.50	Deferred Stock Unit Agreement with W. S. Oakes	10.d.50	Form 10-K 200
10.d.51	Deferred Stock Unit Agreement with M. G. Powell.	10.d.51	Form 10-K 200
10.d.52	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.52	Form 10-K 200
10.d.53	Deferred Stock Unit Agreement with N. L. Brue.	10.d.53	Form 10-K 200
10.d.54	Deferred Stock Unit Agreement with W. H. Bruett.	10.d.54	Form 10-K 200
10.d.55	Deferred Stock Unit Agreement with M. O. Burns	10.d.55	Form 10-K 200
10.d.56	Deferred Stock Unit Agreement with L. E. Chickering.	10.d.56	Form 10-K 200
10.d.57	Deferred Stock Unit Agreement with J. V. Cleary.	10.d.57	Form 10-K 200
10.d.58	Deferred Stock Unit Agreement with D. R. Coates.	10.d.58	Form 10-K 200
10.d.59	Deferred Stock Unit Agreement with E. A. Irving.	10.d.59	Form 10-K 200
10.d.60	Director Deferral Agreement with E. A. Bankowski	10.d.60	Form 10-K 200
10.d.61	Director Deferral Agreement with M. O. Burns	10.d.61	Form 10-K 200
10.d.62	Director Deferral Agreement with D. R. Coates.	10.d.62	Form 10-K 200
10.d.63	Director Deferral Agreement with E. A. Irving.	10.d.63	Form 10-K 200
10.d.64	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.64	Form 10-Q June 2004
10.d.65	Deferred Stock Unit Agreement with N. L. Brue.	10.d.65	Form 10-Q June 2004
10.d.66	Deferred Stock Unit Agreement with W. H. Bruett.	10.d.66	Form 10-Q June 2004
10.d.67	Deferred Stock Unit Agreement with M. O. Burns	10.d.67	Form 10-Q June 2004
10.d.68	Deferred Stock Unit Agreement with D. R. Coates.	10.d.68	Form 10-Q June 2004
10.d.69	Deferred Stock Unit Agreement with K. C. Hoyt.	10.d.69	Form 10-Q June 2004
10.d.70	Deferred Stock Unit Agreement with E. A. Irving.	10.d.70	Form 10-Q June 2004
10.d.71	Deferred Stock Unit Agreement with M. A. vanderHeyden. . . .	10.d.71	Form 10-Q June 2004
10.d.72	Director Deferral Agreement with E. A. Bankowski	10.1	Form 8-K Dec. 2, 2004

10.d.73	Director Deferral Agreement with M. O. Burns	10.2	Form 8-K Dec. 2, 2004
10.d.74	Director Deferral Agreement with E. A. Irving.	10.3	Form 8-K Dec. 2, 2004
10.d.75	Officer Deferral Agreement with S. C. Terry.	10.4	Form 8-K Dec. 2, 2004
10.d.76	Officer Deferral Agreement with W. S. Oakes.	10.5	Form 8-K Dec. 2, 2004
10.d.77	Board of Directors' Resolutions Amending Deferred. . . . . . Compensation Plan	10.1, 10.2	Form 8-K Dec. 30, 2004
10.d.78	Officer Compensation Table	10.d.78	Form 10-K 200
10.d.79	2005 Management Compensation Plan Description.	10.d.79	Form 10-K 200
10.d.80	Green Mountain Power Corporations Officers' Supplemental . . Retirement Plan with C. L. Dutton	10.d.80	Form 10-K 200
10.d.81	Green Mountain Power Corporations Officers' Supplemental . . Retirement Plan with R. J. Griffin	10.d.81	Form 10-K 200
10.d.82	Green Mountain Power Corporations Officers' Supplemental . . Retirement Plan with W. S. Oakes	10.d.82	Form 10-K 200
10.d.83	Green Mountain Power Corporations Officers' Supplemental . . Retirement Plan with M. G. Powell	10.d.83	Form 10-K 200
10.d.84	Green Mountain Power Corporations Officers' Supplemental . . Retirement Plan with D. J. Rendall, Jr.	10.d.84	Form 10-K 200
10.d.85	Green Mountain Power Corporations Officers' Supplemental . . Retirement Plan with S. C. Terry	10.d.85	Form 10-K 200
10.d.86	Green Mountain Power Corporation 2004 Stock Incentive Plan .	10.d.86	Form 10-K 200
10.d.87	Green Mountain Power Corporation Third Amended and Restated. Deferred Compensation Plan for Certain Officers.	10.d.87	Form 10-K 200
14	Green Mountain Power Corporation's Code of Ethics. . . . . . and Conduct dated October 6, 2003.	14	Form 10-K 200
23.a.2	Consent of Deloitte and Touche LLP	23.a.2	
24	Limited Power of Attorney.	24	