GREEN MOUNTAIN POWER CORP
Form 10-K
March 13, 2007

UNITED STATES
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

For the fiscal year ended December 31, 2006

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 001-08291

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.)
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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. oYes þNo

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. oYes þNo

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. þYes oNo

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filero Accelerated filerþNon-accelerated filero

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). oYes þNo

The aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2006, was approximately $179,174,308 based on the closing price of $33.99 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 28, 2007, was 5,307,592.

DOCUMENTS INCORPORATED BY REFERENCE

Certain portions of Part III of this Form 10-K (Items 10, 11, 12, 13 and 14) will be incorporated by reference to the Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be filed with the Commission pursuant to Regulation 14A.

Green Mountain Power Corporation
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PART I
FORWARD-LOOKING STATEMENTS

This report contains statements that may be considered forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934. You can identify these statements by forward-looking words such as "may," "could," "should," "would," "intend," "will," "expect," “forecast,” "anticipate," "believe," "estimate," "continue" or similar words. We intend these forward-looking statements to be covered by the safe harbor provisions for forward-looking statements contained in the Private Securities Reform Act of 1995 and are included in this statement for purposes of complying with these safe harbor provisions. You should read statements that contain these words carefully because they discuss the Company's future expectations, contain projections of the Company's future results of operations or financial condition, or state other "forward-looking" information.

There may be events in the future that we are not able to predict accurately or control and that may cause actual results to differ materially from the expectations described in forward-looking statements. Investors are cautioned that all forward-looking statements involve risks and uncertainties, and actual results may differ materially from those discussed in this document, including the documents incorporated by reference in this document. These differences may be the result of various factors, including changes in general, national, regional, or local economic conditions, changes in fuel or wholesale power supply costs, regulatory or legislative action or decisions, and other risk factors identified from time to time in our periodic filings with the Securities and Exchange Commission.

The factors referred to above include many, but not all, of the factors that could impact the Company's ability to achieve the results described in any forward-looking statements. You should not place undue reliance on forward-looking statements. You should be aware that the occurrence of the events described above and elsewhere in this document, including the documents incorporated by reference, could harm the Company's business, prospects, operating results or financial condition. We do not undertake any obligation to update any forward-looking statements as a result of future events or developments. There are risks, uncertainties and other factors that could cause actual results to be different from those projected. Some of the reasons that 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") 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 92,000 customers. The Company was incorporated under the laws of Vermont on April 7, 1893.

Our sources of retail and wholesale revenue for the year ended December 31, 2006 were as follows:

- 31.3 percent from residential customers;
- 31.1 percent from small commercial and industrial customers;
- 20.5 percent from large commercial and industrial customers;
- 11.1 percent from sales to other utilities; and
- 6.0 percent from other sources.

Approximately 94.3 percent of all of our revenue resulted from the sale of electricity for the period 2006 compared to 96.1 percent in 2005.

See MD and A, Item 7 below, for further information about revenues.

During 2006, our energy resources for retail sales of electricity were obtained as follows:

- 50.8 percent from hydroelectric sources (38.4 percent Hydro Quebec, 7.8 percent Company-owned, and 4.6 percent independent power producers);
- 47.3 percent from a nuclear generating source (the Entergy Nuclear Vermont Yankee, LLC ("ENVY") nuclear plant described below);
- 4.3 percent from wood;
- 2.2 percent from natural gas or oil; and
- measurably no percent from wind after sales of renewable energy certificates.

The 4.6 percent excess of resources obtained was sold on a short-term basis through the wholesale market operated by ISO New England, Inc., formerly the New England Power Pool ("NEPOOL").

In 2006, we estimate that we purchased under existing contracts or generated approximately 105 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. The excess of supply is sold, or in years when our demand is greater than our generation and long term contract resources, remaining retail and wholesale sales were met, through short-term market purchases and sales and represent primarily volumetric differences between purchase commitments and our customers' retail demand. See Note J of Notes.

A major source of the Company’s power supply is our entitlement to a share of the power generated by the 620 megawatt ("MW") nuclear generating plant owned and operated by 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 approximately 100MW to 106MW 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 the common stock of Vermont Electric Power Company, Inc. ("VELCO"). VELCO, through its investment in Vermont Transco LLC (“Transco”), owns the high-voltage transmission system in Vermont. On June 30, 2006, substantially all of VELCO’s assets were transferred to Transco in exchange for 2.4 million Class A Membership Units and Transco’s assumption of VELCO’s debt. VELCO has a 30.8 percent ownership interest in Transco. Transco now owns and operates the transmission system in Vermont over which bulk power is delivered to all electric utilities in the State. The Company owns approximately 21.9 percent of the membership units of Transco. For further information concerning Transco, see Transco below.

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. As a RTO, ISO-NE provides 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, such as warmer than normal temperatures in summer months, 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 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, Colchester, 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 Transco 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,				
	2006	**2005**	**2004**	**2003**	**2002**
Net system peak in MW (1)	365.5	351.9	326.7	330.2	342.0
MWH Production and purchases (2)					
Hydro	1,038,129	879,147	777,292	838,855	901,998
Wind, net of renewable energy credits sold	821	1,484	-	8,568	9,577
Nuclear	965,080	816,989	764,010	884,585	771,781
Conventional steam	87,993	93,258	89,622	100,402	85,910
Internal combustion	6,239	7,547	13,026	12,603	4,090
Combined cycle	38,081	22,328	32,224	68,488	81,362
Bilateral and system purchases(3)	344,534	647,094	804,962	2,426,091	2,347,086
Total production	2,480,877	2,467,847	2,481,136	4,339,592	4,201,804
Less: non-firm sales to other utilities	439,542	365,000	408,601	2,284,003	2,104,172
Production for firm sales	2,041,335	2,102,847	2,072,535	2,055,589	2,097,632
Less firm sales	1,966,159	2,011,568	1,973,093	1,937,376	1,951,959
Losses and company use (MWH)	75,176	91,279	99,442	118,213	145,673
Losses as a % of total production	3.03%	3.70%	4.01%	2.72%	3.47%
System load factor (4)	63.8%	68.2%	72.4%	71.1%	70.0%
Net Production (% of Total)					
Hydro	41.8%	35.6%	31.3%	19.3%	21.5%
Wind	0.0%	0.1%	0.0%	0.2%	0.2%
Nuclear	38.9%	33.1%	30.8%	20.4%	18.3%
Conventional steam	3.5%	3.8%	3.6%	2.3%	2.0%

Internal combustion	0.3%	0.3%	0.5%	0.3%	0.1%
Combined cycle	1.5%	0.9%	1.3%	1.6%	1.9%
Bilateral and system purchases	13.9%	26.2%	32.5%	56.0%	56.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Sales (MWH)					
Residential	583,228	598,606	580,710	581,047	553,294
Commercial & industrial - small	707,031	717,451	698,000	696,598	695,504
Commercial & industrial - large	668,522	686,260	684,104	651,709	689,618
Other	4,143	5,935	7,112	4,986	9,773
Total retail sales	1,962,924	2,008,252	1,969,926	1,934,340	1,948,189
Sales to Municipals & Cooperatives (Rate W)	3,235	3,316	3,166	3,036	3,770
Total Requirements Sales	1,966,159	2,011,568	1,973,093	1,937,376	1,951,959
Other Sales for Resale	439,542	365,000	408,601	2,284,003	2,104,172
Total sales (MWH)	2,405,701	2,376,568	2,381,694	4,221,379	4,056,131
Average Number of Electric Customers					
Residential	77,862	76,481	75,507	74,693	73,861
Commercial and industrial small	13,951	13,752	13,515	13,344	13,165
Commercial and industrial large	27	27	24	25	29
Other	62	60	62	65	65
Total	91,902	90,320	89,108	88,127	87,120
Average Revenue Per KWH (Cents)					
Residential	12.90	13.12	13.15	12.98	12.96
Commercial & industrial - small	10.57	10.66	10.63	10.40	10.44
Commercial & industrial - large	7.36	7.55	7.44	7.41	7.31
Total retail	10.20	10.38	10.32	10.22	10.09
Average Use and Revenue Per Residential Customer					
KWh's	7,491	7,827	7,691	7,779	7,491
Revenues	$ 966	$ 1,027	$ 1,012	$ 1,010	$ 971

(1) MW - Megawatt is one thousand kilowatts.
(2) MWH - Megawatt hour is one thousand kilowatt hours.
(3)Includes MWh generated for renewable energy credits sold
(4) 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 also 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. Customers, 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. 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 Transco, 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 Transco as interstate public utilities under Parts II and III of the Federal Power Act, as amended and supplemented by the National Energy Act.

We provide transmission service to ten 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 2006.

On July 17, 1997, the FERC approved our Open Access Transmission Tariff. 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.

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.

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. When 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 was approved by the VPSB in December, 2003. We are required to file a new, updated integrated resource plan on or before May 15, 2007.

RECENT RATE DEVELOPMENTS

On December 22, 2006, the VPSB approved a rate increase of 9.09%, effective January 1, 2007, and an Alternative Regulation Plan (the “2007 Alternative Regulation Plan”) for the Company to be effective for three years beginning February 1, 2007. The rate increase allows us to recover increases in power and transmission costs in 2007 compared to 2006. The 2007 Alternative Regulation Plan’s principal components include a power supply adjustment mechanism that allows the Company to adjust rates on a quarterly basis to reflect power supply cost changes in excess of $300,000 plus 90 percent of amounts in excess of $300,000 per quarter and an earnings sharing mechanism to permit sharing of earnings in excess of the Company's allowed return on equity and earnings shortfalls below the Company's allowed return on equity. The earnings sharing proposal allows the Company to earn up to 75 basis points above its allowed return on equity and to recover earnings shortfalls in excess of 100 basis points below its allowed return on equity. Under the 2007 Alternative Regulation Plan, the Company’s allowed return on equity is 10.25 percent for 2007. We believe the 2007 Alternative Regulation Plan creates opportunities and incentives for the Company to become more efficient, improve customer service, decouple earnings from increased electricity sales, streamline cost recovery, share efficiency savings with customers, increase credit quality, and reduce regulatory and borrowing costs borne by customers.

During February 2006, we requested that the VPSB grant an accounting order to allow us to defer up to approximately $3.7 million in incremental hurricane-related power supply expenses incurred in the first quarter of 2006, and to also allow us to defer and amortize $1.3 million of incremental hurricane-related benefits realized in the fourth quarter of 2005 against these costs. The accounting order was approved by the VPSB in February 2006, and allowed the Company to defer power supply expenses of $2.1 million in the first quarter of 2006.

The VPSB issued an order on December 22, 2003 approving the Company's 2003 Rate Plan (the "2003 Rate Plan"). The 2003 Rate Plan was in effect from January 1, 2004 through December 31, 2006. The 2003 Rate Plan:

· Allowed 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 cost of service schedules pursuant to the plan in November 2004, November 2005, and December 2006 respectively, and received approval from the VPSB to implement the plan's 1.9 percent rate increase, effective January 1, 2005, and the plan’s 0.9 percent rate increase, effective January 1, 2006.

· The 2003 Rate Plan set and capped the Company's allowed return on equity at 10.5 percent for the period beginning January 1, 2003 through December 31, 2006 and provided 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 2007 Alternative Regulation Plan and the 2003 Rate Plan, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Rates and 2007 Rate Plan.

MERGERS AND ACQUISITIONS

On June 22, 2006, the Company announced that it had entered into an Agreement and Plan of Merger, dated as of June 21, 2006 (the “Merger Agreement”), among Northern New England Energy Corporation, a Vermont corporation (“NNEEC”), Northstars Merger Subsidiary Corporation, a Vermont corporation and wholly-owned subsidiary of NNEEC (the “Merger Sub”), and the Company, pursuant to which Merger Sub will be merged with and into the Company (the “Merger”). The Company will be the surviving company in the Merger as a wholly-owned subsidiary of

NNEEC. NNEEC is a wholly owned subsidiary of GazMétro Limited Partnership ("GazMétro"), a limited partnership organized under the laws of the Province of Québec.

Under the terms of the Merger Agreement, at the effective time of the Merger, each issued and outstanding share of the Company's common stock, including all deferred stock and stock options issued but not exercised, par value $3.33 1/3 per share (other than shares which are held by any wholly-owned subsidiary of the Company or in the treasury of the Company or which are held by NNEEC or Merger Sub, or any direct or indirect wholly-owned subsidiary of NNEEC, all of which shall cease to be outstanding and shall be canceled and none of which shall receive any payment with respect thereto, and other than dissenting shares), will be converted into the right to receive $35.00 in cash, without interest thereon.

The Company and NNEEC have made customary representations, warranties and covenants in the Merger Agreement. In particular, the Company covenants to NNEEC, subject to certain exceptions, (1) not to solicit or knowingly encourage or facilitate the making or submission of any alternative acquisition proposal nor initiate, encourage, or participate in any discussions or negotiations with, or furnish any non-public information to, any person (other than NNEEC or Merger Sub) in connection with any acquisition proposal; (2) for its Board of Directors not to withdraw or modify the Board's action to recommend the Merger in a manner adverse to NNEEC; and (3) to use its best efforts to convene a special meeting of the Company's shareholders to consider and vote upon the approval of the Merger Agreement and the Merger.

On June 21, 2006, Merger Sub entered into employment agreements with the following employees of the Company: Christopher L. Dutton, Robert J. Griffin, Mary G. Powell, Donald J. Rendall, Jr., Walter Oakes and Dawn D. Bugbee. These agreements generally provide that they shall become effective upon consummation of the Merger and that the employees subject to the employment agreements will continue to be employed by the Company for a period of at least three years thereafter. Each agreement contains provisions relating to compensation, benefits, the applicable employee's rights upon a Change of Control (as such term is defined in the employment agreement), confidentiality and the effect of the termination of an employee's employment.

A more complete description of the terms of the proposed Merger is set forth in the Company's Current Report on Form 8-K dated June 22, 2006 and in the Company's Proxy Statement on Schedule 14A dated September 20, 2006.

On October 31, 2006, a special meeting of the Company's shareholders was held in Colchester, Vermont to vote on the proposal to approve the Merger Agreement so that the Merger can occur. At such meeting, the Company's shareholders approved the Merger Agreement.

A petition for approval of the Merger was filed with the VPSB on August 7, 2006 and remains pending. The VPSB completed hearings on the Merger in January 2007 and the petition is presently under advisement by the VPSB. We currently expect a VPSB decision whether to approve the Merger to be issued by the end of March 2007 and, if approval is granted, what conditions to impose. A decision could be issued before or after the expected time; there is no deadline for issuance of the decision. All other regulatory approvals required for the Merger have been obtained.

SINGLE CUSTOMER DEPENDENCE

The Company's one major retail customer, IBM, accounted for 15.0 percent, 15.3 percent and 16.4 percent of the Company's retail operating revenues in 2006, 2005 and 2004, respectively. No other retail customer accounted for more than 1.0 percent of our revenue during the past three years.

We believe, based on a number of projected variables, that a hypothetical shutdown of the IBM facility, inclusive of the tertiary effects on commercial and residential customers, may necessitate a modest retail rate increase because the Company could sell some of the contracted power supply resources into the wholesale market at prices in excess of those charged to IBM. The amount of such an increase would change materially as a result of any significant reductions in wholesale energy prices or increases in retail rates paid by IBM.

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 energy options such as propane, natural gas or oil for heating, cooling and water heating, and self-generation. Another competitive risk 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 the VPSB and other State officials determine that the public good will be served by such sales. Since 1987, the Department has made limited retail sales of electricity.

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. There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont.

CONSTRUCTION AND CAPITAL REQUIREMENTS

Our capital expenditures for 2004 through 2006 and projected for 2007 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 2,041,335 MWh of energy for retail and requirements wholesale customers for the twelve months ended December 31, 2006. The corresponding maximum one-hour integrated demand during that period was 365.5 MW on August 2, 2006. This compares to the previous all-time peak of 351.9 MW on July 19, 2005. 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 J of Notes.

Net Electricity Generated and Purchased and Capacity at Peak

	Generated and Purchased for the year ended December 31, 2006		Capacity At time of of annual peak	
	MWH	**percent**	**KW**	**percent**
Wholly-owned plants:				
Hydro	160,140	7.8%	23,370	6.4%
Diesel and Gas Turbine	6,239	0.3%	58,550	15.9%
Wind*	821	0.0%	960	0.3%
Jointly-owned plants:				
Wyman #4	583	0.0%	6,470	1.8%
Stony Brook I	26,116	1.3%	30,936	8.4%
McNeil	29,099	1.4%	5,770	1.6%
Long Term Purchases:				

Vermont Yankee/ENVY	965,080	47.3%	97,451	26.5%
Hydro Quebec	784,098	38.4%	107,391	29.2%
Stony Brook I	11,965	0.6%	14,124	3.8%
Other:				
Independent Power Producers	151,382	7.4%	22,593	6.1%
-				-
ISO-NE and Short-term purchases, net	(94,188)	-4.7%	-	-
Net Own Load	2,041,335	100.0%	367,615	100.0%

*Net of renewable energy certificates sold representing 10,000MWh

Vermont Yankee Nuclear Power Corporation Contract

On July 31, 2002, VYNPC completed the sale of its nuclear power plant to ENVY. ENVY, through its power contract with VYNPC, provides approximately 100MW to 106MW of the plant output to the Company through 2012, adjusted for uprate, which is expected to represent approximately 35 percent of our projected energy requirements.

Prices under the Power Purchase Agreement (the "PPA") between VYNPC and ENVY 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 in 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 is 33.6 percent. VYNPC's primary role consists of administering its power supply contract with ENVY and its contracts with VYNPC's present sponsors.

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. The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the ENVY plant. 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. The Company maintains insurance for unscheduled outages for the Vermont Yankee plant and those costs are included in rates. The Company’s outage insurance coverage is for 60 days and includes a $1 million deductible amount and is limited to $6 million total coverage for incremental on-peak energy replacement costs. 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, net of insurance recoveries.

Vermont Yankee's current operating license expires March 2012. Since the Company no longer owns an interest in the 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.

During the year ended December 31, 2006, we used 965,080 MWh of Vermont Yankee energy (supplied by ENVY) representing 47.3 percent of the net electricity generated and purchased ("net power supply") by the Company.

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Other Power Supply Risks, and Notes B and J of Notes for additional information.

Hydro Quebec Power Supply Contracts

Highgate Interconnection. 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 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 control or operation of these facilities to affect the Company's deliveries of power from Hydro Quebec under our current power contract commitments.

Hydro Quebec Interconnection. VELCO and certain other ISO-NE members have entered into agreements with Hydro Quebec, which constructed in two phases 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, derive approximately 9.0 percent of the total power-supply benefits associated with the ISO-NE/Hydro Quebec interconnection. The Company, in turn, receives approximately one-third of the Vermont share of those benefits. The benefits of the interconnection include:

· deliveries of a portion of our contract power supply entitlements from Hydro Quebec;
· 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 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 I facilities are schedule to be retired in 2007.

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, 2006, the present value of the Company's obligation was approximately $3.6 million. The Company's projected future minimum payments under the Phase II support agreements are approximately $354,000 for each of the years 2007-2011 and an aggregate of $1.8 million for the years 2012-2015.

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 Notes B and I of Notes.

The bulk of our purchases from Hydro Quebec are pursuant to two power supply contract 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 $8.0 million to the Company in exchange for certain power purchase options. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Power Contract Commitments, and Note J of Notes.

During 2006, we used 464,139 MWh under Schedule B, and 319,959 MWh under Schedule C3 of the VJO Contract, representing 38.4 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"). The Morgan Stanley Contract expired on December 31, 2006. The contract provided 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 - Power Contract Commitments and Note J of Notes.

JP Morgan Contract -The Company entered into a contract with JP Morgan Ventures Energy Corporation (the "JP Morgan Contract") during 2006 to purchase approximately 10 percent of the Company's retail load requirements for a four-year period commencing January 1, 2007 and ending December 31, 2010. The JP Morgan Contract will help the Company cover a portion of its retail load requirements. Approximately 10 percent of our off-peak load remains exposed to market prices during the period 2007 - 2010, as well as peak and off-peak load variances caused by weather variations or other factors. Management will continue to monitor the markets for opportunities to cover the Company's open position or purchase this energy in the spot market. The power costs reflected in the JP Morgan Contract and the forecasted costs of the Company's remaining open position are included in the Company's 2007 rates.

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 2006, the Company sold 94,188 MWh representing 4.7 percent of the Company's net power supply.

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 the ownership 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 2006, we used 38,081 MWh from this plant, representing 1.9 percent of our net power supply. See Notes H and J of Notes.

Wyman Unit #4. The W. F. Wyman Unit #4, 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 2006, we used 583 MWh from this unit, representing less than 1.0 percent of our net power supply. See Note H of Notes.

McNeil Station. The J.C. McNeil station (the "McNeil Plant"), located in Burlington, Vermont, is a wood chip and gas-fired steam plant with a capacity of 53.0 MW. The Burlington Electric Department is the principal owner and operator of the McNeil Plant. We have an 11.0 percent or 5.8 MW joint ownership 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 2006, we used 29,099 MWh from this unit, representing 1.4 percent of our net power supply. See Note H of Notes.

Independent Power Producers. The VPSB has adopted rules that implement for Vermont the purchase requirements established by federal law in the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Under the rules, qualifying facilities have the option to sell their output to a central state-appointed purchasing agent under a variety of long-term and short-term, firm and non-firm pricing schedules. Each of these schedules is based upon the projected Vermont composite system's power costs that would be required but for the purchases from independent producers. The State's purchasing agent assigns the energy so purchased, and the costs of purchase, to each Vermont retail electric utility based upon the utility’s 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' rates.

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 2006 was approximately 34.1 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 2006, through our direct contracts and VEPPI, we purchased 151,382 MWh of qualifying facilities production, representing 7.4 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 2006, Company-owned hydroelectric plants produced 160,140 MWh, representing 7.8 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 transmitted power for its owners in Vermont, including power from the New York Power Authority and other power contracted for by Vermont utilities. VELCO is a member of ISO-NE and represents Vermont electric utilities in some pool and RTO matters. See Note B of Notes and Transco.

Transco. In June 2006, VELCO transferred substantially all of its assets to Transco in exchange for 2.4 million Class A Membership Units and Transco’s assumption of VELCO’s debt. VELCO has a 30.8 percent ownership interest in Transco. Transco now owns and operates the transmission system in Vermont over which bulk power is delivered to all electric utilities in the State. The Company owns approximately 21.9 percent of the membership units of Transco. See Note B of Notes.

Fuel. See the discussion about energy resources under the description of the Company in Item 1.

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 these units during 2006. None of the utilities from which we expect to purchase oil- or gas-fired capacity in 2006 has advised us of any expected difficulties in securing 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.

Searsburg 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 in Searsburg, Vermont. 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 2006, the project produced 10,821 MWh, and the Company sold renewable energy certificates representing 10,000 MWh. Net of renewable energy credit sales, the wind-powered facility output represented less than 1.0 percent of the Company’s net power supply.

SEGMENT INFORMATION

Financial information about the Company's industry segment, the electric utility, is presented in Item 6, Selected Financial Data, and in the 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.

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, 365.5 MW, occurred on August 2, 2006.

EMPLOYEES

As of December 31, 2006, 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 2006, 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. 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 rate design was approved by the VPSB in 2005. The new rate design has not adversely affected operating results. The Company’s rate design objectives are to provide a stable pricing structure and to reflect accurately the cost of providing electric services. Our current rate design helps to achieve these goals. Because 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.

CURTAILABLE SERVICE

At December 31, 2006, we had 18 customers receiving service under a curtailable power tariff. This tariff allows customers to receive a portion of their electricity at favorable rates except during times when energy prices or demand are high. 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. This program is 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 H 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. The net liability of the discontinued segment consists primarily of deferred tax liabilities. For information regarding our unregulated businesses, see Note A of Notes.

EXECUTIVE OFFICERS

The names, ages, and positions of our Executive Officers, in alphabetical order, as of March 8, 2007 are:

Dawn D. Bugbee 50
Vice President, Chief Financial Officer and Treasurer since March 2006. Ms. Bugbee was previously Chief Financial Officer at the Northwestern Medical Center, Inc. in St. Albans, Vermont since 1996.

Christopher L. Dutton 58
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 50
Vice President, Power Supply and Risk Management since March 2006. Mr. Griffin was Chief Financial Officer and Principal Accounting Officer from December 2003 to March 2006. Vice President since July 2003. Treasurer from February 2002 until March 2006. Controller from October 1996 to December 2003. Manager of General Accounting from 1990 to 1996.

Walter S. Oakes 60
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 46
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. Prior to HRworks, Inc. Ms. Powell was Senior Vice President of Community Banking for Key Bank of Vermont, from 1992 to 1997.

Donald J. Rendall 51
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.

The Board of Directors of the Company and its wholly-owned subsidiaries, as appropriate, elect 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 will be presented in the Company's Proxy Statement to Shareholders, 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 1A. RISK FACTORS
The risk factors included in Item 7A - Quantitative and Qualitative Disclosures About Market Risk - are incorporated by reference herein.

ITEM 1B. UNRESOLVED STAFF COMMENTS
None.

ITEM 2. PROPERTIES
GENERATING FACILITIES
Our Vermont properties are located in five areas and are interconnected by transmission lines of Transco and New England Power Company. We own and operate eight hydroelectric generating stations with a total nameplate rating of 36.1 MW. We also own two gas-turbine generating stations with an aggregate nameplate rating of 63.6 MW. We own two diesel generating stations with an aggregate nameplate rating of 6.0 MW. We also own a wind generating facility with a nameplate rating of 6.1 MW.

We also own:
· 33.6 percent of the outstanding common stock of Vermont Yankee Nuclear Power Corporation and, through its contract with ENVY, we are entitled to 106.2 MW of the capacity of the Vermont Yankee nuclear generating plant,
    · 1.1 percent (7.0 MW of a total 620 MW) joint-ownership share of the Wyman #4 plant located in Maine,

- 8.8 percent (30.2 MW of a total 352 MW) joint-ownership share of the Stony Brook I intermediate units located in Massachusetts, and
- 11.0 percent (5.5 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 owned, at December 31, 2006, approximately 287 miles of overhead transmission lines consisting of 1.5 miles of 115 kV, 10.5 miles of 69 kV, 5.4 miles of 46 kV, 267.6 miles of 34.5 kV and 2.0 miles of 13.8 kV lines. Our distribution system included approximately 2,500 miles of overhead lines of 2.4 to 34.5 kV and approximately 442 miles of underground cable of 2.4 to 34.5 kV. We own approximately 104,800 kVA of substation transformer capacity in transmission substations and 416,200 kVA of substation transformer capacity in distribution substations and approximately 1,025,000 kVA of transformers for step-down from distribution to customer use.

The Company owns 34.8 percent of the Highgate transmission facilities, consisting of 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 ISO-NE/Hydro Quebec interconnection.

We also own 29.2 percent of the common stock and 30 percent of the preferred stock of VELCO. The Company also owns approximately 21.9 percent of the membership units of Transco. VELCO has a 30.8 percent ownership interest in Transco, which owns and operates the high-voltage transmission system interconnecting electric utilities in the State of Vermont.

The VELCO/Transco properties consist of approximately 580 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 National Grid; on the south with the facilities of Vermont Yankee; and on the north with lines of Hydro Quebec through the Highgate converter station and tie line jointly owned by the Company and several other Vermont utilities.

VELCO's wholly-owned subsidiary, VETCO, owns approximately 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 E, 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	Energy Source	Name Plate Rating MW
Wholly Owned				
Hydro	Middlesex, VT	Middlesex #2	Hydro	3.6
	Marshfield, VT	Marshfield #6	Hydro	5.0
	Vergennes, VT	Vergennes #9	Hydro	2.6
	W. Danville, VT	W. Danville #15	Hydro	1.0
	Colchester, VT	Gorge #18	Hydro	3.0
	Essex Jct., VT	Essex #19	Hydro	7.2
	Waterbury, VT	Waterbury #22 (1)	Hydro	5.5
	Bolton, VT	DeForge #1	Hydro	8.4
Diesel	Vergennes, VT	Vergennes #9	Oil	4.0
	Essex Jct., VT	Essex #19	Oil	2.0
Gas Turbine	Berlin, VT	Berlin #5	Oil	46.6
	Colchester, VT	Gorge #16	Oil	17.0
Wind	Searsburg, VT	Searsburg	Wind	6.1
Jointly Owned				
Steam	Yarmouth, ME	Wyman #4	Oil	7.0
	Burlington, VT	McNeil (2)	Wood/Gas	5.5
Combined	Ludlow, MA	Stony Brook #1	Oil/Gas	30.2
Total Winter Capability				154.7

(1) Repairs to dam are complete. Our generation facility is awaiting re-licensing.

(2) The Company's entitlement in McNeil is 5.5 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 H of Notes.

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

At a special meeting of shareholders held on October 31, 2006, there were 5,289,161 shares of common stock outstanding and entitled to vote, of which 3,921,722 were represented in person or by proxy. The following matters were submitted to a vote of the Company's shareholders at the special meeting with the voting results designated below each such matter:

1.

Shareholders were asked to approve or disapprove the Agreement and Plan of Merger by and among the Company, Northern New England Energy Corporation and Northstars Merger Subsidiary Corporation with 3,815,744 votes for, 85,694 votes against, and 20,284 votes abstaining.

2. Shareholders were asked to approve or disapprove granting authority to proxy holders to vote in their discretion with respect to the approval of any proposal to postpone or adjourn the special meeting to a later date for a reasonable business purpose, including to solicit additional proxies in favor of the approval of the Agreement and Plan Of Merger if there are not sufficient votes for approval of the Agreement and Plan of Merger at the special meeting, with 3,680,489 votes for, 212,081 votes against, and 29,152 votes abstaining.
3. There were no broker non-votes with respect to the matters voted upon by shareholders at the special meeting.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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 2006 and 2005:

	HIGH	LOW
2006		
First Quarter	$ 30.50	$ 27.10
Second Quarter	34.00	27.74
Third Quarter	34.00	33.00
Fourth Quarter	34.10	33.22
2005		
First Quarter	$ 30.88	$ 27.87
Second Quarter	30.00	28.85
Third Quarter	33.03	28.75
Fourth Quarter	33.08	26.62

The number of common stockholders of record as of February 28, 2007 was approximately 4,256, $3.33333 par value.

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2005	$0.25	$0.25	$0.25	$0.25
2006	$0.28	$0.28	$0.28	$0.28

PERFORMANCE GRAPH

The following performance graph presents the yearly percentage change in the cumulative total shareholder return on the Company's Common Stock, as compared to the cumulative total returns of the Standard and Poor's 500 Stock Index and that of the members of Edison Electric Institute's Index.

	12/01	12/02	12/03	12/04	12/05	12/06
Green Mountain Power Corporation	**100.00**	**116.10**	**135.35**	**171.01**	**176.43**	**215.52**
S & P 500	**100.00**	**77.90**	**100.24**	**111.15**	**116.61**	**135.03**
EEI Investor-Owned Electrics	**100.00**	**85.27**	**105.30**	**129.34**	**150.09**	**181.25**

ITEM 6. SELECTED FINANCIAL DATA
Results of Operations for the years ended December 31,

In thousands, except per share data	2006	2005	2004	2003	2002
Operating Revenues	$ 240,476	$ 245,860	$ 230,574	$ 280,470	$ 274,608
Operating Expenses	224,355	229,779	215,096	265,164	259,528
Operating Income	16,121	16,081	15,478	15,306	15,080
Other Income					
AFUDC - equity	106	29	449	387	233
Other	1,117	1,696	1,638	1,692	2,252
Total other income	1,223	1,725	2,087	2,079	2,485
Interest Charges					
AFUDC - borrowed	(48)	(18)	(285)	(267)	(103)
Other	7,461	6,778	6,791	7,324	6,273
Total interest charges	7,413	6,760	6,506	7,057	6,170
Net Income from continuing operations before preferred dividends	9,931	11,046	11,059	10,328	11,395
Net Income (Loss) from discontinued operations, including provisions for loss on disposal	192	134	525	79	99
Dividends on Preferred Stock	-	-	-	3	96
Net Income Applicable to Common Stock	$ 10,123	$ 11,180	$ 11,584	$ 10,404	$ 11,398
Common Stock Data					
Basic earnings per share-continuing operations	$ 1.88	$ 2.12	$ 2.18	$ 2.08	$ 2.02
Basic earnings per share-discontinued operations	$ 0.04	$ 0.03	$ 0.10	$ 0.01	$ 0.02
Basic earnings per share	$ 1.92	$ 2.15	$ 2.28	$ 2.09	$ 2.04
Diluted earnings per share from continuing operations	$ 1.85	$ 2.09	$ 2.10	$ 2.01	$ 1.96
Diluted earnings (loss) per share from discontinued operations	$ 0.04	$ 0.03	$ 0.10	$ 0.01	$ 0.02
Diluted earnings per share	$ 1.89	$ 2.12	$ 2.20	$ 2.02	$ 1.98
Cash dividends declared per share	$ 1.12	$ 1.00	$ 0.88	$ 0.76	$ 0.60
Weighted average shares outstanding-basic	5,270	5,195	5,083	4,980	5,592
Weighted average equivalent shares outstanding-diluted	5,348	5,284	5,254	5,140	5,756

Financial Condition as of December 31

In thousands	2006	2005	2004	2003	2002
Assets					
Utility Plant, Net	$ 246,992	$ 236,911	$ 232,712	$ 228,862	$ 223,476
Other Investments	37,262	20,663	18,959	13,706	21,552

Current Assets	44,256	64,312	44,809	31,688	31,432
Deferred Charges	57,223	51,729	55,120	55,590	60,390
Non-Utility Assets	229	653	755	1,105	995
Total Assets	$ 385,962	$ 374,268	$ 352,355	$ 330,951	$ 337,845
Capitalization and Liabilities					
Common Stock Equity	126,636	$ 117,374	$ 109,581	$ 99,915	$ 91,722
Redeemable Cumulative Preferred Stock	-	-	-	-	55
Long-Term Debt, Less Current Maturities	109,000	79,000	93,000	93,000	93,000
Capital Lease Obligation	3,562	3,944	4,493	4,963	5,287
Current Liabilities	31,219	63,156	33,815	22,715	38,491
Deferred Credits and Other	113,004	108,420	109,295	108,281	107,349
Non-Utility Liabilities	2,541	2,374	2,171	2,077	1,941
Total Capitalization and Liabilities	$ 385,962	$ 374,268	$ 352,355	$ 330,951	$ 337,845

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

From time to time in this report, we may make statements that constitute “forward-looking statements” within the meaning of the “safe-harbor” provisions of the Private Securities Litigation Reform Act of 1995. Such statements are based on our then current expectations and are subject to a number of risks and uncertainties that could cause actual results to differ materially from those addressed in the forward-looking statements. 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 and other regulatory risks
- energy supply and demand, outages and other power supply volume risks
- power supply price risks
- customer concentration risks
- pension and postretirement health care risks
- customer service quality
- changes in regional market and transmission rules
- contingent obligations or rights contained in contractual commitments
- credit risks, including availability, terms, and use of capital and counterparty credit quality
- general economic and business environment
- changes in technology
- nuclear and environmental issues
- alternative regulation and cost recovery (including stranded costs)
- weather
- customer growth and changes in customer demands, and
- acts of terrorism

Additional risk factors that may cause such a difference are discussed in Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” and elsewhere herein and are incorporated herein.

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

Executive Overview - Green Mountain Power Corporation (the "Company") typically generates most of its earnings from retail electricity sales. Our retail customer base typically grows at an average annual rate of between one and two percent, about average for most electric utility companies in New England. In periods of very high energy prices, wholesale revenues and expenses arising primarily from sales and purchases to accommodate volumetric difference between energy supplies and customer demand can affect earnings to a significant degree. The Company's prices for retail electricity sales are regulated by the Vermont Public Service Board ("VPSB").

On June 22, 2006, the Company announced that it had entered into an Agreement and Plan of Merger, dated as of June 21, 2006 (the "Merger Agreement") under which the Company has agreed to become a wholly-owned subsidiary of Northern New England Energy Corporation ("NNEEC"), which is a wholly-owned subsidiary of GazMetro Limited Partnership("GazMetro"); a Quebec-domiciled gas distribution enterprise. Under the Merger Agreement, all issued and outstanding shares of common stock, including all deferred stock and stock options issued but not exercised, of the Company will be acquired for $35.00 per share upon closing. The merger is summarized below under "Mergers and Acquisitions."

The Company increased its common stock dividend in February 2006 from an annual rate of $1.00 per share to $1.12 per share. The Company's dividend payout ratio during 2006 was approximately 60 percent of 2006 earnings from continuing operations. The Company's dividend payout ratio during 2005 was approximately 47 percent of 2005 earnings from continuing operations. The Merger Agreement permits the Company to pay quarterly dividends of $0.28 per share. Under the Merger Agreement, the Company has agreed not to increase the dividend prior to the closing of the Merger without the permission of NNEEC.

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. The Company's allowed rate of return on its regulated operations was capped at 10.5 percent in 2006, reduced by amounts normally excluded for purposes of setting rates determined by the VPSB. Nearly all of the Company's continuing operations are treated for ratemaking purposes as regulated operations. Due principally to transaction costs related to the merger and exclusions mentioned above, the Company's 2006 return on equity was 8.35 percent. The Company operated through December 31, 2006 under a three-year rate plan approved by the VPSB in December 2003 (the "2003 Rate Plan"). The 2003 Rate Plan covers the period 2004 - 2006 and has provided the Company with a stable, predictable rate path through 2006 and a plan for full recovery of the Company's principal regulatory assets. The 2003 Rate Plan is described in more detail below under "Rates."

On December 22, 2006, the VPSB approved a rate increase of 9.09%, effective January 1, 2007, and an Alternative Regulation Plan (the "2007 Alternative Regulation Plan") for the Company to be effective for three years beginning February 1, 2007. The rate increase allows the Company to recover increases in power and transmission costs in 2007 compared to 2006. The 2007 Alternative Regulation Plan's principal components include a power supply adjustment mechanism and an earnings sharing mechanism to permit sharing of earnings in excess of the Company's allowed return on equity and earnings shortfalls below the Company's allowed return on equity.

For further discussion of the Company's 2007 Alternative Regulation Plan, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Rates.

MERGERS AND ACQUISITIONS

On June 22, 2006, the Company announced that it had entered into the Merger Agreement with NNEEC, Northstars Merger Subsidiary Corporation, a Vermont corporation and a wholly-owned subsidiary of NNEEC (the "Merger Sub"), and the Company, pursuant to which Merger Sub will be merged with and into the Company. The Company will be the surviving company in the Merger as a wholly-owned subsidiary of NNEEC. NNEEC is a wholly owned subsidiary of GazMétro.

Under the terms of the Merger Agreement, at the effective time of the Merger, each issued and outstanding share of the Company's common stock, including all deferred stock grants and stock options issued but unexercised, par value $3.33 1/3 per share (other than shares which are held by any wholly-owned subsidiary of the Company or in the treasury of the Company or which are held by NNEEC or Merger Sub, or any direct or indirect wholly-owned subsidiary of NNEEC, all of which shall cease to be outstanding and shall be canceled and none of which shall receive any payment with respect thereto, and other than dissenting shares), will be converted into the right to receive $35.00 in cash, without interest thereon.

The Company and NNEEC have made customary representations, warranties and covenants in the Merger Agreement. In particular, the Company covenants to NNEEC, subject to certain exceptions, (1) not to solicit or knowingly encourage or facilitate the making or submission of any alternative acquisition proposal nor initiate, encourage, or participate in any discussions or negotiations with, or furnish any non-public information to, any person (other than NNEEC or Merger Sub) in connection with any acquisition proposal; (2) for its Board of Directors not to withdraw or modify the Board's action to recommend the Merger in a manner adverse to NNEEC; and (3) to use its best efforts to convene a special meeting of the Company's shareholders to consider and vote upon the approval of the Merger Agreement and the Merger.

On June 21, 2006, Merger Sub entered into employment agreements with the following employees of the Company: Christopher L. Dutton, Robert J. Griffin, Mary G. Powell, Donald J. Rendall, Jr., Walter Oakes and Dawn D. Bugbee. These agreements generally provide that they shall become effective upon consummation of the Merger and that the employees subject to the employment agreements will continue to be employed by the Company for a period of at least three years thereafter. Each agreement contains provisions relating to compensation, benefits, the applicable employee's rights upon a Change of Control (as such term is defined in the employment agreement), confidentiality and the effect of the termination of an employee's employment.

A more complete description of the terms of the proposed Merger is set forth in the Company's Current Report on Form 8-K dated June 22, 2006 and in the Company's Proxy Statement on Schedule 14A dated September 20, 2006.

On October 31, 2006, a special meeting of the Company's shareholders was held in Colchester, Vermont to vote on the proposal to approve the Merger Agreement so that the Merger can occur. At such meeting, the Company's shareholders approved the Merger Agreement.

A petition for approval of the Merger was filed with the VPSB on August 7, 2006 and still remains pending. The VPSB completed hearings on the Merger in January 2007 and the petition is presently under advisement by the VPSB. We currently expect a VPSB decision whether to approve the Merger petition to be issued by the end of March 2007 and, if approval is granted, what conditions to impose. A decision could be issued before or after the expected time; there is no deadline for issuance of the decision.

In 2001, as part of an order approving a retail rate settlement, the VPSB ordered that the Company and customers share equally any premium above book value realized by the Company's shareholders in any merger, subject to an $8 million limit, adjusted for inflation. As part of the merger approval petition, the Company and NNEEC proposed to satisfy this order through creation of the Green Mountain Power Efficiency Fund (the "Efficiency Fund"), under which the Company will invest in efficiency, renewable energy and new technology programs what will return to our customers benefits covering the full amount required by the 2001 order. As proposed, the Company will earn a return of and on Efficiency Fund investments. The Department of Public Service has filed testimony supporting the Efficiency Fund proposal. One intervener, International Business Machines Corporation ("IBM"), filed testimony on November 21, 2006, opposing the Efficiency Fund and requested the Board to order a refund of $8 million, adjusted by inflation since 2001, to customers. If the VPSB rejects the proposed Efficiency Fund and orders a refund as proposed by IBM, NNEEC could assert such a condition constitutes a material adverse event under the Merger Agreement.

All other regulatory approvals required for the Merger have been obtained.

OTHER

Power supply expenses were equivalent to approximately 62.6 percent of total operating expenses in 2006. 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."

We also discuss other risks, including customer concentration risk related to our largest customer, 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 Transco, LLC (“Transco”), the operating subsidiary of Vermont Electric Power Company, Inc. ("VELCO"), and an opportunity for increased 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.

Earnings Summary

Earnings Summary	**For the Years Ended**		
	2006	**2005**	**2004**
Consolidated diluted earnings per share of common stock	$ 1.89	$ 2.12	$ 2.20
Consolidated diluted earnings per share of common stock-continuing operations	$ 1.85	$ 2.09	$ 2.10
Consolidated return on average common equity	8.35%	9.85%	11.06%

Discussion for Year Ending 2006 compared to 2005:
Earnings per share decreased primarily as a result of $1.6 million in merger related transactions costs incurred during 2006 in which NNEEC, an affiliate of GazMetro, has agreed to acquire the Company at $35.00 per common share.

The Company's regulated earnings were capped in 2006 and 2005 to the allowed rate of return on equity of 10.5 percent under the Company’s rate plan, approved in 2003. The regulated earnings cap calculation excludes costs that are not allowed for rate setting purposes, which reduce the Company's earning potential and limit the Company's ability to achieve its allowed rate of return on equity for its operations as a whole. Revenues in excess of allowed costs are deferred and appear in the Company’s financial statements under the caption “Deferred Regulatory Revenues.” The following table shows the comparative impact of the earnings cap and merger costs on net income:

Green Mountain Power Consolidated Earnings
Full Year Comparative Results
2006, 2005 and 2004

	Income (in thousands)			Diluted Earnings per Share		
	2006	2005	2004	2006	2005	2004
Net Income	$ 10,123	$ 11,180	$ 11,584	1.89	2.12	2.20
Impact of Earnings Cap	$ 5,732	$ 582	$ 0			
Less: Tax Effect	(2,293)	(233)	0			
Impact of Earnings Cap, net of taxes	3,439	349	0	0.64	0.07	0.00
Merger Costs	$ 1,621	$ 0	$ 0	0.30	0.00	0.00
Weighted Avg Shares-Fully Diluted (in thous)				5,348	5,285	5,254

Any deferred regulatory revenues will be applied in future years as a reduction to regulatory assets, or possibly refunded to customers as a credit on customer bills, as directed by the Department of Public Service.

Retail and other operating revenues for 2006 decreased by $3.7 million compared with 2005, reflecting the deferral of regulatory revenues of approximately $5.7 million, which is recorded as a reduction to revenue. The milder summer and winter weather caused consumption to decrease resulting in a reduction in revenue of $4.0 million. These impacts were partially offset by an increase of $3.7 million in sales of utility services to other utilities and municipalities and approximately $2 million in additional revenue generated from the 0.9 percent rate increase that took effect in January 2006, along with a slight increase in the number of customers.

Total retail megawatt hour sales of electricity decreased by 2.3 percent in 2006 compared with 2005. Sales to residential, small commercial and industrial, and large commercial and industrial customers in 2006 decreased by 2.7, 1.5 and 2.7 percent, respectively, compared with 2005, a year that was affected by warmer than normal summer temperatures. Increased revenues from the sale of utility services to other utilities and large industrial customers in 2006 contributed approximately $3.7 million more to retail revenue growth than in 2005. Other operating expenses increased by $4.1 million in 2006, reflecting an increase of $3.6 million in utility services expense, compared to 2005. These sales of utility services are intended to build strategic expertise and revenue to the benefit of both customers and shareholders. The remaining $500,000 increase in other operating expenses related to an increase in distribution expenses.

Power supply expenses decreased $9.5 million in 2006 compared with 2005, reflecting increased entitlements under long-term contracts and greater output from the Company’s hydroelectric generating facilities, which reduced reliance on expensive wholesale market purchases. This significant cost savings was the major driver contributing to the amount of deferred regulatory revenues. The Company exercised an option to purchase more power in 2006 under its long-term contract with Hydro-Quebec. A temporary increase in the Company’s entitlement from the Entergy Nuclear Vermont Yankee (“ENVY”) nuclear power plant (the “Vermont Yankee plant”) also reduced dependence on market purchases. Prices for additional 2006 contract entitlements and Company hydroelectric generation were below wholesale market prices for 2006 and substantially below 2005 wholesale market prices. Market prices in 2005 were abnormally high, reflecting the interruption of gas supplies in the Gulf caused by hurricane activity and warmer than normal summer temperatures.

Depreciation and amortization expenses were $704,000 lower in 2006 compared to the previous year, reflecting the impact of a new depreciation schedule adopted as a result of a study that was completed in 2005 and implemented in 2006.

Provisions for income taxes increased by approximately $823,000 in 2006 compared to the same period last year, reflecting an increase in pretax book income and an increase in the effective tax rate due to nondeductible merger expenses, which were partially offset by a 8.7% decrease in the Vermont state corporate income tax rate.

Equity in earnings of affiliates and non-utility operations increased by $1.2 million in 2006 compared to 2005 as a result of the Company's additional $17.1 million in equity investments in Transco, which owns and operates most of the transmission grid in Vermont.

The increase in other expenses of $1.6 million in 2006 related to costs incurred in connection with the proposed Merger.

Earnings from discontinued operations totaled $.04 per share in 2006, compared with $.03 per share in 2005, primarily as a result of adjustments to tax valuation allowances arising from the realization of tax capital losses.

On June 30, 2006, VELCO's assets were transferred to Transco in exchange for 2.4 million Class A Membership Units and Transco's assumption of VELCO's debt. VELCO and its employees will manage the operations of Transco under an operating agreement that includes the Company, Central Vermont Public Service Corporation and most of Vermont's electric utilities. We own approximately 29 percent of VELCO and 21.9 percent of Transco.

On December 22, 2006 the Company received approval from the VPSB for a rate increase of 9.09 percent effective January 1, 2007, with an allowed rate of return of 10.25 percent. The Company also received approval to implement the 2007 Alternative Regulation Plan.

For further discussion of the Company's 2007 Alternative Regulation Plan, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk - Rates.

Discussion for Year Ending 2005 compared to 2004:
Total retail megawatt hour sales of electricity increased by 1.9 percent in 2005, compared with the same period in 2004. Sales to residential and small commercial and industrial customers increased by 3.0 percent and 2.7 percent, respectively, while sales to large commercial and industrial customers increased by 0.3 percent in 2005. Revenues from the sale of utility services to other utilities and large industrial and commercial customers increased by approximately $4.3 million in 2005, compared with the prior year. Wholesale revenues in 2005 also increased by $5.6 million compared with 2004, reflecting substantially higher wholesale energy prices in 2005. Other operating expenses increased by $5.5 million in 2005, reflecting an increase of $4.3 million in utility services expense. The Company's utility services business is designed to recover some of its administrative and staffing costs from other parties, ultimately reducing costs to customers and improving financial results between rate cases.

Power supply expenses increased $6.0 million in 2005 compared with 2004 due to increased costs of market purchases to serve marginal load, increased purchases of power under the contract with Hydro Quebec, an increase in the cost of power under the power supply contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"), and increased costs of transmission line losses and congestion charges allocated within the New England power pool by ISO New England ("ISO-NE"), the regional system operator. Congestion charges represent the cost of delivering energy to customers and reflect energy prices, customer demand, and the demands on transmission and generation resources. The Company paid an average market price of approximately $95 per megawatt hour for system purchases during hours when customer demand exceeded supply during 2005, compared to $57 per megawatt hour in the same period last year, inclusive of the effects of congestion and line losses. Our cost of market purchases in 2005 rose approximately $2.3 million accordingly. Increased hydro production and deliveries under long-term power supply contracts with Hydro Quebec and Vermont Yankee Nuclear Power Corporation ("VYNPC") had a significant dampening effect on the increase in power supply expenses the Company experienced in 2005.

Maintenance expenses, depreciation and amortization, and transmission expenses also increased during 2005 compared with 2004. Maintenance expenses increased by $1.5 million, reflecting an increase in transmission and distribution line maintenance and maintenance of our gas turbines. Depreciation and amortization were $1.1 million higher than in the previous year, reflecting increased plant investments and a $539,000 increase in amortization of regulatory assets. Transmission expenses increased by $797,000 during 2005, compared with the prior year, as a result of an increase in charges allocated for system support in New England by ISO-NE, increased retail sales of energy and an increase in investments by VELCO, the entity that in 2005 owned and operated most of the transmission grid in Vermont.

Earnings from discontinued operations totaled $.03 per share in 2005 compared with $.10 per share in the prior year, reflecting diminished exposure to outstanding litigation against an inactive Northern Water Resources ("NWR") subsidiary that led to reversal of previously recorded reserves in 2004.

Critical Accounting Policies

We believe 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 contracts that qualify as derivatives; revenue recognition, particularly as it relates to unbilled and deferred revenues; the assumptions that we make regarding our defined benefit pension and postretirement health care plans; the assumptions that we make about derivatives; and management judgments about the expected outcome of litigation for contingencies. These accounting policies, among others, affect significant judgments and estimates used in the preparation of our consolidated financial statements.

Regulatory Accounting

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 or benefits, typically treated as expenses or income by unregulated entities, to be deferred and expensed or benefited in future periods. Costs are deferred as regulatory assets when the Company concludes that future revenue will be provided to permit recovery of the previously incurred cost. Revenue may also be deferred as regulatory liabilities that would be returned to customers by reducing future revenue requirements. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence and legal representations. Management's conclusions on the recovery of regulatory assets represent a critical accounting estimate.

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 satisfies the criteria under SFAS 71, the Company would be required to write off its regulatory assets, net of regulatory liabilities.

Regulatory assets and liabilities		**Total At December 31, 2006**		**2005**		**Amortizable 2006 balances included in rates in 2007**
Regulatory assets:				(in thousands)		
Demand-side management programs	$	4,376	$	5,835	$	4,376
Purchased power costs		3,683		1,812		3,683

Pine Street barge canal	12,070	12,861	6,732
Derivative liability regulatory assets	22,526	30,135	-
Pension funding regulatory asset	11,789	-	-
Other regulatory assets	5,954	5,809	3,559
Total regulatory assets	60,398	56,452	18,350
Regulatory liabilities:			
Accumulated cost of removal	21,494	21,105	21,494
Deferred regulatory revenues	6,260	582	582
Derivative asset regulatory liability	468	15,342	-
Other regulatory liabilities	7,738	6,485	5,855
Other deferred liablilities	5,759	7,737	3,062
Total regulatory liabilities	41,719	51,251	30,993
Regulatory assets net of regulatory liabilities	$ 18,679	$ 5,201	$ (12,643)

The 2007 Alternative Regulation Plan provides for amortization and recovery of the regulatory assets and regulatory liabilities as listed above, beginning January 2007, except for pension funding and the power supply portion of derivative regulatory assets and regulatory liabilities, which will not be amortized. The Pine Street Barge Canal regulatory asset is subject to amortization over a period of 20 years without a return on the remaining balance of the asset. The VPSB approval of regulatory assets under the 2003 Rate Plan and the 2007 Alternative Regulation Plan has eliminated much uncertainty regarding the recovery of these assets.

Pursuant to the adoption by the Company of SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R), a regulatory asset for the total unfunded pension obligation was created. The following table summarizes the effect of adoption of SFAS 158 on the Company's consolidated financial statements.

in thousands	**December 31 2005**	**2006 Activity**	**SFAS 158 and regulatory reclassification**	**December 31 2006**
Prepaid pension	$ 2,170	$ 1,623	$ (3,793)	$ -
Regulatory asset FAS 158 pension funding obligation offset	-	-	11,789	11,789
Deferred tax asset - federal	3,271	(1,749)	2,459	3,982
Deferred tax asset - state	868	(464)	653	1,057
Accumulated other comprehensive income	3,263	(3,074)	(188)	-
Minimum pension funding liability	(5,486)	5,486	-	-
Total pension funding obligation	-	(317)	(12,116)	(12,433)
SERP liability	(3,897)	(202)	4,099	-
Post retirement health care liability	(832)	493	338	-
Deferred tax liability - federal	(695)	(520)	(2,561)	(3,776)
Deferred tax liability - state	(184)	(138)	(680)	(1,002)

Derivatives

The derivative regulatory assets and liabilities represent the value of certain power supply contracts and interest rate positions ("swaps") that must be marked to fair value as derivatives under current accounting rules. The fair value of derivatives can vary significantly based on assumptions, including interest rates, price volatility for the power supply contracts and expected average forward market prices. The Company records contract specified prices for electricity as expense in the period used, as opposed to the fair market values of derivatives, 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 more detail under Power Supply and Other Derivatives. The final settlement of an interest rate swap will be amortized over the life of the related bond issue as a component of interest expenses.

Revenue Recognition
Our operating revenues are derived principally from 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 ("line losses") during transmission and distribution. The Company estimates its range of line losses at between 3.0 percent and 5.0 percent. The Company estimates that a substantial change of 1.5 percent (e.g., from 3.5 percent to 5 percent) in its line loss rate used for calculating its unbilled revenues would result in a pre-tax change of approximately $300,000.

Defined Benefit Plans
The Company's defined benefit pension and postretirement health care plans' costs 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. See Note G in the Notes to Consolidated Financial Statements for a discussion of sensitivities around certain defined benefit plan assumptions.

Contingencies
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," under "Liquidity and Capital Resources", in Note A, "Significant Accounting Policies," in Note G, "Pension and Retirement Plans" and in Note H, "Commitments and Contingencies."

Results of Operations
Operating Revenues and MWh Sales - Operating revenues, megawatt hour ("MWh") sales and number of customers for the years ended 2006, 2005 and 2004 were as follows:

	For the Years ended December 31,					
		2006		**2005**		**2004**
			(dollars in thousands)			
Operating Revenues						
Retail*	$	205,851	$	208,494	$	200,241
Regulatory Revenue (Deferred) Recognized		(5,678)		(582)		2,977
Net Retail Revenue	$	200,173	$	207,912	$	203,218
Sales for Resale		26,642		28,298		22,652
Other Revenues		13,661		9,650		4,704
Total Operating Revenues	$	240,476	$	245,860	$	230,574
MWH Sales-Retail		1,962,924		2,008,250		1,969,925
MWH Sales for Resale		442,777		368,317		411,769
Total MWH Sales		2,405,701		2,376,567		2,381,694

Average Number of Customers

	For the Years ended December 31,		
	2006	**2005**	**2004**
Residential	77,862	76,481	75,507

Commercial and Industrial	13,978	13,779	13,539
Other	62	60	62
Total Number of Customers	91,902	90,320	89,108

Comparative changes in operating revenues are summarized below:

Change in Operating Revenues		**2005 to 2006**		**2004 to 2005**		**2003 to 2004**
				(In thousands)		
Retail Rates	$	2,110	$	4,285	$	(1,027)
Regulatory revenue (deferred) recognized		(5,096)		(3,559)		1,857
Retail Rates, net of regulatory revenue		(2,986)		726		830
Retail Sales Volume		(4,753)		3,968		3,671
Resales and Other Revenues		2,355		10,592		(54,397)
Increase (Decrease) in Operating Revenues	$	(5,384)	$	15,286	$	(49,896)

In 2006, retail revenues decreased $7.7 million or 3.7 percent compared with 2005, due to:

- Decreased retail residential revenues of $1.3 million, or 1.7 percent, arising from a 2.7 percent decrease in sales of electricity and a 0.9 percent retail rate increase effective January 1, 2006; and

- Increased retail small commercial and industrial ("C&I") revenues of $300,000, or 0.4 percent, arising from a 1.5 percent decrease in sales of electricity and a 0.9 percent retail rate increase effective January 1, 2006; and

- Decreased retail large C&I revenues of $1.4 million or 2.6 percent, arising from a 2.7 percent decrease in sales of electricity and a 0.9 percent retail rate increase effective January 1, 2006.

Wholesale revenues decreased by $1.7 million in 2006 or 5.9 percent compared with the prior year, reflecting a 20 percent increase in volume sales but substantially lower market prices for electricity. These lower prices also affected the prices paid for wholesale market purchases.

Other operating revenue increased by $4.0 million or 41.6 percent, reflecting a $3.7 million increase from the sale of utility services to other utilities and large industrial customers. Other operating expense increased by a similar amount, reflecting the cost of sales for these activities.

In 2005, total retail revenues increased 4.7 million or 2.6 percent compared with 2004, due to:

- Increased retail residential revenues of $3.5 million, or 4.7 percent, arising from a 3.0 percent increase in sales of electricity and a 1.9 percent retail rate increase effective January 1, 2005; and

- Increased retail small commercial and industrial ("C&I") revenues of $3.4 million, or 4.6 percent, arising from a 2.7 percent increase in sales of electricity and a 1.9 percent retail rate increase effective January 1, 2005; and

- Increased retail large C&I revenues of $1.2 million or 2.4 percent, arising from a 0.3 percent increase in sales of electricity and a 1.9 percent retail rate increase effective January 1, 2005.

These increases were partially offset by $3.0 million in deferred revenues recognized in 2004 under the 2003 Rate Plan.

Wholesale revenues increased by $5.6 million in 2005, compared with the prior year, reflecting substantially higher market prices for electricity. These higher prices also affected the prices paid for wholesale market purchases.

Other operating revenue more than doubled, increasing revenue by $4.9 million and reflected a $4.3 million increase from the sale of utility services to other utilities and large industrial customers. Other operating expense increased by a similar amount, reflecting the cost of sales for these activities.

Power Supply Expenses - Power supply expenses constituted 62.6, 65.3 and 67.0 percent of total operating expenses for the years 2006, 2005 and 2004, respectively.

The Company's most significant power supply contracts are the Hydro Quebec-Vermont Joint Owners ("VJO") Contract (the "VJO Contract"), the Vermont Yankee Nuclear Power Corporation Contract (the "VYNPC Contract"), through which we buy power from ENVY's nuclear power plant, and the Morgan Stanley Contract. The Morgan Stanley Contract expired December 31, 2006, was replaced by a contract with JP Morgan Venture Energy Corporation (the "JP Morgan Contract").

Power supply expenses decreased $9.5 million in 2006 compared with 2005 reflecting increased entitlements under long-term contracts and greater output from the Company's hydroelectric generating facilities that reduced reliance on more expensive wholesale market purchases and other miscellaneous purchases as follows:

· Market purchases declined by approximately $20 million on reduced purchases of 192,000 megawatt hours in 2006 compared to 2005. Other bilateral contracts declined by $2.7 million on reduced purchases of 19,000 megawatt hours.

· Purchases from Morgan Stanley decreased by $2.4 million reflecting the absence of a scheduled outage at the ENVY nuclear power plant in 2006.

These decreases were offset by the following:

· Increased purchases from VYNPC totaled $7.9 million on increased volumes of 148,000 megawatt hours in 2006 compared to 2005, and resulted from a temporary increase in entitlements during a process ("uprate") to increase the output of the ENVY nuclear power plant and because 2006 had no scheduled outage for the plant which operates under an eighteen month refueling schedule.

· Increased entitlements under the VJO Contract with Hydro-Quebec amounted to 103,000 megawatt hours at a cost of $3.9 million, and resulted from the VJO's exercise of an option to increase the load factor under the contract.

· Increased precipitation was principally responsible for increased purchases from Independent Power Producers ("IPPs") of $3.2 million for 20,000 additional megawatt hours.

· Hydroelectric production was up substantially as the Company's generation costs increased by only $402,000 on 44,000 additional megawatt hours of production.

The additional 2006 contract entitlements and Company hydroelectric generation were purchased or generated, on average, at prices below the wholesale market price for 2006 and substantially below 2005 wholesale market prices. Market prices in 2005 were extremely high reflecting the interruption of gas supplies in the Gulf caused by hurricane activity and warmer than normal summer temperatures.

Power supply expenses increased by $6.0 million in 2005 when compared with 2004, and resulted from the following:

·

A $2.3 million increase in the cost of market purchases caused primarily by higher wholesale market prices ($1.4 million) and a reduction of credits for the auction of transmission rights allocated by ISO-NE ($840,000);

· A $2.3 million increase in power supply expenses under agreements with Hydro Quebec caused by increased megawatt hour purchases of electricity;

· A $1.5 million increase in purchases from Morgan Stanley caused primarily by an increase in contract prices; and

· A $654,000 increase in the costs of electricity supplied by independent power producers caused by production increases due to higher levels of precipitation.

These increases were partially offset by a $922,000 decrease in the cost of power under our contract with VYNPC.

Other Operating Expenses - Other operating expenses increased $4.5 million, or 18.3 percent, in 2006 compared with 2005, primarily as a result of a $3.6 million increase in expenses associated with the sale of utility services and a $381,000 increase in administrative and general expenses.

Other operating expenses increased $5.5 million, or 28.3 percent, in 2005 compared with 2004, primarily as a result of a $4.3 million increase in expenses associated with the sale of utility services and an $852,000 increase in administrative and general expenses.

Transmission Expenses - Transmission expenses decreased $154,000, or 0.9 percent, in 2006 compared with 2005 resulting from regional transmission credits from ISO New England to VELCO.

Transmission expenses increased $797,000, or 5.1 percent, in 2005 compared with 2004 resulting from a $400,000 increase in system-wide allocation of costs associated with voltage control and reactive power (“VAR”) in New England. The remainder of the increase is due primarily to increased sales of energy and investment in VELCO and Transco transmission facilities allocable to the Company.

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.

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, through its subsidiary Transco, 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 and 21.9 percent of Transco.

In January 2005, the project received regulatory approval from the VPSB. The project is estimated to cost approximately $200 million through 2008. VELCO intends to finance the costs of constructing the Northwest Reliability Project in part through increased equity investment, primarily in Transco. In October 2004, the Company invested $4.6 million in VELCO to support this project and other transmission projects. During 2006, the Company invested $17.1 million in Transco and plans to invest $8.4 million in 2007 for transmission infrastructure projects. The Company is evaluating opportunities to invest an additional $19 million in Transco during 2007 for similar purposes. 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 approximately 5 percent of pool transmission facility upgrades in other New England states.

Maintenance Expenses - Maintenance expense decreased $275,000 or 2.5 percent in 2006 compared with 2005 due to a $204,000 decrease in maintenance expenditures on gas turbines.

Maintenance expense increased $1.5 million or 15.4 percent in 2005 compared with 2004, due to a $641,000 increase in maintenance expenditures on gas turbines and a $486,000 increase in distribution expenses, principally for right-of-way maintenance programs.

Depreciation and Amortization - Depreciation and amortization expense decreased $704,000 in 2006 or 4.7 percent compared with 2005 reflecting the impact of a new depreciation schedule adopted as a result of a study that was completed in 2005 and implemented in 2006, and a $213,000 decrease in amortization of conservation expenditures.

Depreciation and amortization expense increased $1.1 million in 2005 or 8.2 percent compared with 2004 due to a $604,000 increase in depreciation of utility plant in service and a $539,000 increase in amortization of conservation expenditures.

Taxes other than income - Taxes other than income taxes increased $252,000, or 3.8 percent, in 2006 compared with 2005 due to a $233,000 increase in property taxes and a $19,000 increase in gross revenue tax.

Taxes other than income taxes decreased $98,000, or 1.5 percent, in 2005 compared with 2004 due to a $238,000 decrease in property tax offset partially by a $144,000 increase in gross revenue tax.

Income Taxes - Income tax expense increased $823,000, or 14.5 percent, in 2006 compared with 2005 due to an increase in the Company’s taxable income, $1.6 million of which was related to nondeductible merger expenses.

Income tax expense decreased $86,000, or 1.5 percent, in 2005 compared with 2004 due to a decrease in the Company’s pre-tax income.

Total Other Income (net of other deductions) - Total other income decreased $502,000, or 29.1 percent, in 2006 compared with 2005 primarily due to $1.6 million in merger expense, partially offset by increased earnings of VELCO and earnings of Transco LLC.

Total other income decreased $362,000, or 17.4 percent, in 2005 compared with 2004 primarily due to $402,000 of one-time gains in 2004 on the sale of non-utility property, and a decrease of $420,000 in equity returns capitalized on regulatory assets in 2005, partially offset by increased earnings of VELCO.

Interest Expense - Interest expense increased $653,000, or 9.7 percent, in 2006 compared with 2005 primarily due to the interest expense on $30 million new first mortgage bonds issued in 2006.

Interest expense increased $254,000, or 3.9 percent, in 2005 compared with 2004 primarily due to a $266,000 decrease in interest capitalized on conservation expenditures that are being recovered under the Company's 2003 Rate Plan. Once plant or regulatory assets begin to be recovered in the rates we collect, interest is no longer capitalized on those assets.

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 were the first utility in the northeast to join the CCX, and have achieved our voluntary goal to reduce our emissions by 4 percent below our 1998 - 2001 baseline average by 2006, either directly or by purchasing credits. Participation in this program is not expected to significantly affect Company operating results. As part of our commitment to transparency in our environmental, social and economic activities, we published our second Corporate Responsibility Report, covering 2005, in accordance with the Global Reporting Initiative guidelines. Investors can review the Company's 2005 Corporate Responsibility Report at www.greenmountainpower.biz, Who We Are, Environmental Policies.

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 2006, 2005, and 2004, the Company disbursed approximately $1.4 million, $600,000, and $1.4 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 $4.5 million, net of recoveries. 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 $12.1 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 began to amortize past unrecovered costs in 2005. The Company expects to amortize the full amount of incurred costs over 20 years without a return. If there were a substantial increase in Pine Street remediation costs, it could result in an adverse impact on earnings under the 2007 Alternative Regulation Rate Plan.

RATES

On December 22, 2006, the VPSB approved a 9.09 percent rate increase for the Company, effective January 1, 2007. The rate increase allows us to recover increased power and transmission costs in 2007 compared to 2006. The VPSB also approved the Company's 2007 Alternative Regulation Plan, effective for three years beginning February 1, 2007. The 2007 Alternative Regulation Plan includes the following principal elements:

- A power supply cost adjustment mechanism under which the Company will recover or credit to customers, on a quarterly basis, 90 percent of power supply costs that are $300,000 (per quarter) higher or lower than power supply costs included in rates.
- An allowed rate of return on equity ("ROE") of 10.25 percent for 2007. The allowed ROE adjusts annually, up or down, in the amount of one-half the change in the ten-year Treasury bond rate.
- An annual earnings sharing mechanism under which the Company has the opportunity to earn up to 75 basis points above its allowed ROE and to recover earning shortfalls in excess of 100 basis points below the allowed ROE. Under the plan, certain exclusions, commonly made in setting rates, are applied to determine the Company's earnings and are expected to affect adversely the Company's ability to earn its allowed rate of return on equity for core utility operations.

- Base rates will be adjusted annually, based on the Company's cost of service. Non-power supply cost increases are capped at no more than $1.25 million in 2008 and $1.5 million in 2009, exclusive of ROE adjustments and extraordinary costs in excess of $600,000 per year. Base rate adjustments must be approved by the VPSB.
- The VPSB retains the authority to investigate the Company's rates at any time and to modify or terminate the plan.

The 2007 Alternative Regulation Plan creates opportunities and incentives for the Company to become more efficient, improve customer service, decouple earnings from increased electricity sales, streamline cost recovery, share efficiency savings with customers, increase credit quality, and reduce regulatory and borrowing costs borne by customers.

During February 2006, the Company requested that the VPSB grant an accounting order to allow us to defer up to approximately $3.7 million in incremental hurricane-related power supply expenses to be incurred in the first quarter of 2006, and to also allow the Company to defer and amortize $1.3 million of incremental hurricane-related benefits realized in the fourth quarter of 2005 against these costs. The accounting order was approved by the VPSB in February 2006, allowing the Company to defer power supply expenses of $2.1 million in the first quarter of 2006.

On December 22, 2003, the VPSB approved our 2003 Rate Plan, jointly proposed by the Company and the DPS. The 2003 Rate Plan covered the period from 2003 through 2006. Under the 2003 Rate Plan, the Company's rates remained unchanged through 2004, increased 1.9 percent effective January 1, 2005, and increased an additional 0.9 percent effective January 1, 2006. We submitted a cost of service schedule supporting the rate increases for 2005 and 2006. The Company's allowed return on equity was capped at 10.5 percent for the period January 1, 2003 through December 31, 2006. Certain exclusions, commonly made in setting rates, prevented the Company from achieving its allowed return on equity for its core utility operations for 2006 and 2005. Revenues in excess of allowed costs are deferred and appear in the Company's financial statements under the caption "Deferred Regulatory Revenues." Deferred regulatory revenues will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.

Under the 2003 Rate Plan, the Company began amortizing (recovering), in January 2005, certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

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

- 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;

- The Company and customers shall share equally any premium above book value realized by the Company's shareholders 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:

	At December 31,	
	2006	**2005**
(In thousands)		

Cash and cash equivalents	$	2,031	$	6,500
Current assets	$	44,256	$	64,312
Less current liabilities		31,219		63,156
Net working capital	$	13,037	$	1,156
Net cash provided by operating activities	$	18,142	$	29,771

Cash and cash equivalents decreased by approximately $4.5 million in 2006. Operating cash flows decreased by $11.6 million from the prior year primarily as a result of income tax payments. Net cash used in investing activities totaled $34.1 million, principally for investments in Transco and to construct utility plant.

We expect most of our utility construction expenditures and dividends to be financed by net cash provided by operating activities. We expect to finance our increasing investment in Transco through debt issuance. Material risks to cash flow from operations include regulatory risk, power supply risks, slower than anticipated load growth and unfavorable economic conditions.

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. During 2006, the Company invested $17.1 million in Transco and plans to invest $8.4 million through 2007 for transmission infrastructure projects. The Company is evaluating opportunities to invest an additional $19 million in Transco during 2007 for similar purposes. Our planned investments will fund an increase in the amount of equity in Transco's capital structure and increased transmission investment, principally driven by construction of the Northwest Reliability Project and other Vermont construction projects.

Future capital expenditures, net of contributions in aid of construction of approximately $2.5 million per year and excluding the planned investment in Transco, are expected to range from $25 to $28 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 2007 are as follows:

(In thousands)	**Generation**	**Transmission**	**Distribution**	**Other***	**Total**
Actual:					
2004	$ 3,053	$ 2,898	$ 8,662	$ 5,005	$ 19,618
2005	2,060	596	8,541	6,400	$ 17,597
2006	$ 4,895	$ 1,001	$ 13,869	$ 4,581	$ 24,346
Forecast:					
2007	$ 6,232	$ 4,345	$ 11,368	$ 3,702	$ 25,647

* Other includes Pine Street Barge Canal net expenditures of $1.4 million in 2004 $600,000 in 2005, $1.4 million in 2006 and an estimated $1.1 million in 2007.

Dividend Policy - The Company increased the annual dividend on its common stock in the first quarter of each of the past three years. Our recent dividend history is as follows:

Period Reflecting Dividend Change	**New Annual Dividend Rate**	**Annual Payout Ratio**
2006 1st Quarter	1.12	60%
2005 1st Quarter	1.00	47%
2004 1st Quarter	.88	42%

Payout ratio is computed as annual dividend rate divided by annual earnings from continuing operations.

The Merger Agreement with NNEEC permits the Company to pay quarterly dividends at the current level of $0.28 per common share. Under this agreement, the Company has agreed not to increase the dividend prior to the closing of the merger without the permission of NNEEC.

FINANCING AND CAPITALIZATION

Credit Facilities
Effective June 14, 2006, the Company obtained a five-year revolving credit facility of $30 million with Sovereign Bank and Key Bank replacing the expiring 364-day revolving credit agreement with Bank of America and Sovereign Bank. The Sovereign/Key Bank revolving credit facility is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. This revolving credit facility does not include any material adverse change or material adverse effect clauses, subsequent to the effective date, as pre-conditions for borrowing under the facility. There was no revolving credit short-term debt outstanding at December 31, 2006.

During June 2005, 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 was for $30.0 million, unsecured, and allowed the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was no short-term debt outstanding on the Fleet-Sovereign Agreement at December 31, 2005. There was no non-utility short-term debt outstanding at December 31, 2005. The Fleet-Sovereign Agreement expired June 14, 2006.

On August 3, 2006, the Company closed on the first tranche of the new $30 million First Mortgage Bonds, 6.53% Series, due August 1, 2036 and received $11 million in funds. The primary use of these funds was to partially fund additional capital investments by the Company in Transco. The second tranche of $19 million was received in December 2006 and was used to repay $14 million of First Mortgage Bonds and to repay short-term bank borrowings.

The credit ratings of the Company's first mortgage bonds at December 31, 2006 were:

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

The Moody's rating at December 31, 2006 expired when the $4.0 million First Mortgage Bonds matured in December 2006. Subsequent to year end, the Company obtained a Moody's rating on the $30.0 million First Mortgage Bonds issued during 2006. The rating was reinstated at Baa1.

PERFORMANCE ASSURANCE
The Company is subject to performance assurance requirements associated with its power purchase and sale transactions through ISO-NE under the Financial Assurance Policy for NEPOOL members. While the Company is generally a net seller to ISO-NE, it must post collateral if the net amount owed exceeds its credit limit at ISO-NE. A company's credit limit is calculated as a percentage, based on its credit rating, of its net worth. The Company's present credit limit with ISO-NE is approximately $2.9 million. ISO-NE reviews collateral requirements on a daily basis. As of December 31, 2006, the Company had no collateral requirements with ISO-NE.

The Company is also subject to performance assurance requirements under the VYNPC Contract to purchase power from ENVY. If ENVY, the seller, has commercially reasonable grounds for insecurity regarding the Company's ability to pay for its monthly purchases, ENVY may ask VYNPC and VYNPC may then ask the Company to provide adequate financial assurance (collateral) payments. The Company has never been requested to post collateral under this contract.

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 Company typically utilizes EEI standard contracts for residual power supply contractual arrangements that contain triggers that require posting of letters of credit or other credit assurances if amounts due the creditor party exceed certain thresholds, frequently tied to the Company’s credit rating. The JP Morgan Contract contains certain confidential credit assurance requirements if the Company’s unsecured credit ratings fall below investment grade. While the Company’s principal long-term contracts do not contain these strict provisions, if replacement contracts were entered into today, they likely would contain specified collateral thresholds and credit rating triggers.

The following table presents a summary of certain material contractual obligations and other expected payments existing as of December 31, 2006.

	Future Payments Contractually Due by Period				
At December 31, 2006	**Total**	**2007**	**2008 and 2009**	**2010 and 2011**	**After 2011**
			(In thousands)		
Long-term debt	$ 109,000	$ -	$ -	$ 6,000	$ 103,000
Interest on long-term debt	115,872	7,493	14,986	14,623	78,769
Capital lease obligations	3,592	402	709	709	1,772
Hydro-Quebec power supply contracts	475,117	52,376	103,582	105,676	213,483
JP Morgan contract	75,680	17,029	36,973	21,678	-
Independent Power Producers	120,610	17,145	31,332	29,619	42,514
Stony Brook contract	23,573	3,858	7,844	7,878	3,994
VYNPC PPA	189,308	33,744	73,155	72,118	10,292
Benefit plan contributions*	39,366	3,366	7,150	7,250	21,600
Deferred Compensation	13,136	1,029	2,850	2,546	6,711
Transco capital contributions	24,930	8,400	10,730	5,800	-
Pine Street Barge Canal remediation, excluding recoveries	9,629	1,024	926	458	7,221
Total	$ 1,199,813	$ 145,865	$ 290,237	$ 274,354	$ 489,356

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

*Benefit plan contributions and Deferred Compensation payments are estimated through 2016

Off-Balance Sheet Arrangements and Other Contractual Obligations - 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 own an equity interest in VELCO and Transco, which requires the Company to pay a portion of their operating costs, including debt service costs. We also own an equity interest in VYNPC in which we are obligated to pay a portion of VYNPC’s operating costs based on our Vermont entitlement percentage.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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, customer service quality measures, 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 VJO Contract and the VYNPC Contract, which together are expected to cover approximately 75 to 80 percent of our retail load. The Company also entered into the Morgan Stanley Contract designed to manage wholesale electricity price risks associated with changing fossil fuel prices. The Morgan Stanley Contract made up approximately an additional ten percent of our power supply resources in 2006 and expired December 31, 2006. The Morgan Stanley Contract was replaced with the JP Morgan Contract for the period 2007-2010. The JP Morgan Contract is expected to supply just under 10 percent of the Company's retail load requirements for a four year period commencing January 1, 2007 and ending December 31, 2010. Both the Morgan Stanley Contract and JP Morgan Contract terms are subject to confidentiality agreements.

	2006 MWh	2006 $/MWh	2005 MWh	2005 $/MWh	2004 MWh	2004 $/MWh	Contract Expires
VJO Contract	784,098	$65.38	680,984	$69.61	605,718	$74.47	2015
VYNPC Contract	965,080	$40.15	816,989	$39.67	764,010	$43.63	2012

Purchases under the VJO and VYNPC contract increased in 2006 reflecting the exercise of an option to increase the VJO load factor and the uprate of the Vermont Yankee nuclear power plant that provided the Company with a temporary increase in entitlement. 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 for twenty years beginning in September 1995; and (2) Schedule C3 -- 46 megawatts of firm capacity and associated energy at any time for 20 years, beginning in November 1995.

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 Derivatives."

On July 31, 2002, VYNPC completed the sale of its nuclear power plant to ENVY. VYNPC entered into a Power Purchase Agreement ("PPA") with ENVY under which ENVY is obligated to provide between 100MW to 106MW 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. 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. Current market prices are far above these levels so we do not expect the low market adjuster to affect contract pricing in the near future. We no longer bear the operating costs and risks associated with running and decommissioning the plant.

JP Morgan Contract -The Company entered into the JP Morgan Contract during 2006 to purchase approximately 10 percent of the Company's retail load requirements for a four year period commencing January 1, 2007 and ending December 31, 2010. The JP Morgan Contract will help the Company cover a portion of its retail load requirements. With the JP Morgan Contract in place approximately 10 percent of our off-peak load remains exposed to market prices during the period 2007 - 2010, as well as peak and off-peak load variances caused by weather variations or other factors. Management will continue to monitor the markets for opportunities to cover the Company's open position or purchase this energy in the spot market. The replacement power costs reflected in the JP Morgan Contract and the forecasted costs of the Company's remaining open position are included in the Company's 2007 rates.

Power Supply Price Risk - The Company meets most of its customer demand through a series of long-term physical and financial contracts. 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. There are occasions when the Company's available supply of electricity is insufficient to meet customer demand. During those periods, electricity is purchased at market prices. The Company must also purchase energy at market prices for outages or other delivery interruptions under its principal supply contracts.

We expect more than 90 percent of our estimated load requirements through 2007 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. 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. Under the Company's 2007 Alternative Regulation Plan approved by the VPSB in 2006, the Company obtained an automatic power supply adjustment clause ("Power Supply Adjustor") to adjust rates for higher or lower energy costs without prior regulatory approval under a formula that allows the Company to recover 90 percent of energy price increases in excess of $300,000 on a quarterly basis or return to customers equivalent decreases in energy prices.

As an example, the estimated average variation of power supply costs to rate allowances under the Power Supply Adjustor formula for the past two years was $360,000, and the highest quarterly variation was $780,000. However, future power supply adjustments could include the effects of material outages that would cause the value of the power supply adjustment clause to be much higher.

The Company is charged for a number of power supply ancillary services, including costs for congestion, line losses, reserves, and regulation that vary in part due to changes in the price of energy. The method of settling the cost of congestion and other ancillary services is administered by ISO New-England and is subject to change. During periods of high prices, ancillary charges are volatile and can adversely impact earnings to a significant degree. In periods of high price volatility, we estimate that our power supply expenses could vary in excess of $1 million annually due to changes in line loss and congestion costs. Congestion and loss charges represent the cost of delivering energy to customers and reflect energy prices, customer demand, and the demands on transmission and generation resources.

ISO-NE is implementing a new forward capacity market ("FCM") in an effort to differentiate the price generators receive for capacity at different locations within New England and support new investments. ISO-NE believes that proposed higher capacity payments in constrained areas will encourage the development of new generation where needed. The Company has existing power supply resources that meet most of our present needs. Incrementally, future FCM amounts for load growth beyond 2007 could be material, and if so, would be expected to increase Company rate requirements accordingly. The derating of generation capacity from our wholly-owned units by ISO-NE could require the Company to purchase that lost capacity at market prices. The Company estimates that the 2007 impact of FCM price increases will raise our power supply expenses by approximately $1 million, pre-tax, and those costs are included in our rates.

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. Most of our principal power supply contract counter-parties and generators, including Hydro Quebec and JP Morgan, currently have investment grade credit ratings. ENVY does not have an investment grade rating.

Power Supply and Other Derivatives - The Company's 9701 agreement with Hydro Quebec grants Hydro Quebec an option to call power annually at prices that are expected to be below estimated future wholesale market prices. The terms of the 9701 agreement meet the definition of a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133"). Management has estimated the fair value of the future net cost of this agreement at December 31, 2006 to be approximately $20.6 million. We use forward contracts and power supply swaps to hedge forecasted calls by Hydro Quebec under the 9701 agreement and treat such contracts and swaps as derivatives under SFAS 133.

Under the 9701 Agreement, 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). We expect Hydro Quebec to exercise this option each year.

Hydro Quebec exercised Option A for delivery in January and February 2007. The Company has covered Hydro Quebec's 2007 call at a net cost of $4.9 million. Hydro Quebec's call for 2006 was made during the fourth quarter of 2005 for delivery during January and February, timed to take advantage of extremely high forward energy prices resulting from the effects of hurricanes Katrina and Wilma that interrupted gas production in the Gulf of Mexico. Energy prices in the Northeast are heavily dependent upon natural gas prices. In February 2006, the Company requested an accounting order from the VPSB allowing it to defer in 2006 extraordinary hurricane-related costs. The VPSB granted our request in February 2006 and we recorded a regulatory asset of approximately $2.1 million. These costs are included in rates.

The Company has other less significant derivative positions. The Company entered into forward sales contracts for the months of March and April, 2007 to sell energy excess of forecasted demand to capture forward energy prices that were high by historical standards. The interest rate swaps described below were used to hedge against rising interest rates for the issue of new first mortgage bonds in 2006 and 2007.

The table below presents the Company's estimated market risk of the 9701 agreement and other derivatives estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in wholesale energy prices, which nets to $3.7 million. Actual results may differ materially from the table illustration.

Commodity Price Risk	**At December 31, 2006**	
	Fair Value	**Market Risk**
	(in thousands)	
Interest rate swap	$ 193	$ 19
Power supply swaps	(1,918)	$ (654)
9701 agreement	(20,608)	(3,193)
Forward sale contracts	275	116

	$ (22,058)	$ (3,712)

The table below presents assumptions used to estimate the fair value of the 9701 agreement and other contracts treated as derivatives. 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
Interest rate swap	Deterministic	n/a	n/a	n/a	2007
9701 agreement	Black-Scholes	4.4%	29%-10%	$93	2015
Forward sale contracts	Deterministic	5%	n/a	$70	2007
Power supply Swaps	Deterministic	4.8-5.1%	n/a	$92	2007-2009

In March 2006, the Company entered into an interest rate swap relating to the Company's 2006 issuance of first mortgage bonds to mitigate the risk of rising interest rates. Approximately one-half of the new $30 million first mortgage bonds in 2006 was covered. The interest rate swap was settled on August 2, 2006, with a final gain on settlement of approximately $600,000, which will be amortized over the life of the bond issue as a component of interest expense. See Liquidity and Capital Resources.

In December 2006, the Company entered into a second interest rate swap relating to the Company's anticipated 2007 first mortgage bonds. Approximately $15 million of the $20 million first mortgage bonds proposed for 2007 was covered. The interest rate swap is still outstanding and has a fair value of $193,000 as of December 31, 2006. The final settlement will be amortized over the life of the bond issue as a component of interest expense.

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 - Hydro Quebec had 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. During 2004, Hydro Quebec exercised its third and last option for deliveries occurring principally during 2005 that resulted in an incremental expense of $3.9 million based on current market prices. Hydro Quebec also retains the right to curtail annual energy deliveries to the Company 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, exercised their last option to adjust deliveries by a five percent load factor in the fourth quarter of 2006 for delivery effective November 1, 2006 to October 31, 2007.

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 substantially higher than VJO Contract energy costs. The VJO Contract energy prices are approximately $30 per megawatt hour, while forward prices in 2007 have typically been in excess of $70 per megawatt hour. We expect to purchase in excess of 700,000 megawatt hours during 2007 under the VJO contract, so any significant deficiencies in deliveries would increase power supply costs materially.

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 other 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 under the step-up provision would be approximately $692 million for the remainder of the contract, assuming that all other members of the VJO defaulted by January 1, 2007 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 resell the energy in the wholesale power markets and recover the losses, if any, and/or recover its costs from the defaulting members or its retail customers. 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.

While the Vermont Yankee plant has had an excellent operating record, future unscheduled outages could occur at times when replacement energy costs are well above VYNPC Contract costs. Based on current forward prices, we estimate that the Company could potentially have to pay increased costs of approximately $60,000 to $80,000 for each day that the Vermont Yankee plant experienced an unscheduled outage, if uncovered by insurance. The Company maintains insurance for unscheduled outages for the Vermont Yankee plant and those costs are included in rates. The Company’s coverage is for 60 days of such unscheduled outage and includes a $1 million deductible amount, with a maximum of $6 million coverage for on-peak energy only. Historically, the VPSB has allowed the Company to defer, rather than expense, the higher costs resulting from extraordinary outages at the plant, not otherwise covered by insurance. 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 Vermont Yankee plant resulted in a shutdown of the 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.

The RPP was a part of ENVY's request to uprate or increase the output of the Vermont Yankee nuclear plant that was approved by the VPSB. Under the RPP, we have indemnification rights of 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. In March 2006, the Company and ENVY agreed to a settlement that would pay amounts to the Company sufficient to eliminate the deferred outage costs of approximately $500,000. The settlement agreement is subject to VPSB approval.

The Vermont Yankee plant received final approval for uprating from the Nuclear Regulatory Commission on March 2, 2006. Since that time the ENVY nuclear plant output has increased to the expected uprated power level of 120 percent or 620 megawatts. While the Company has been receiving its normal share at contract rates, it was temporarily obligated to purchase a share of uprate power at market rates. The purchases did not have a material effect on the Company’s net income because the Company either resold the power for a comparable price in the same New England market or used it, displacing other market purchases.

The purchased power agreement between ENVY and VYNPC specifies that our percentage of energy output under VYNPC's contract with ENVY declines after the VY nuclear plant uprating is completed. Post uprate, the Company believes that it is entitled to approximately the same amount of power it received before the uprate process began. VYNPC and ENVY are discussing the calculations, which depend upon determination of the pre-uprate capability of the plant, which is presently disputed. The Company estimates the potential impact of the differing methods of calculation could adversely affect power supply expense by up to $600,000 annually. In the event that the VY nuclear plant is derated in the future, then our rights to energy output could decline proportionately to such derating. If this were to occur, we estimate it would have a material adverse effect on our power supply costs. In this event we would seek recovery of these costs in rates.

The Company is currently a party to a VPSB Docket that was opened to investigate whether the reliability of the increased VY nuclear plant output will be adversely affected by the operation of the plant's steam dryer. On September 18, 2006, the VPSB issued a ruling requiring ENVY to provide additional ratepayer protections that would make Vermont ratepayers whole in the event that VY must reduce power due to uprate-related steam dryer failure. Under the VPSB ruling, these protections will only apply to incremental replacement power costs incurred under the terms of the PPA between ENVY and VYNPC. The additional ratepayer protections are required to remain in effect through a period two months after the first refueling outage in which VY operates successfully with no steam dryer-related outages or derates. VY's next scheduled refueling outage is presently scheduled for May 2007. ENVY has appealed the VPSB ruling to the Vermont Supreme Court, where the appeal is pending.

ENVY has announced that, under current operating parameters, it will exhaust the capacity of its existing nuclear waste storage pool in 2008 and will need to store nuclear waste in so-called "dry fuel storage" facilities to be constructed on the site. ENVY received approval from the Vermont legislature in 2005 and the VPSB in April 2006 to construct and use such dry fuel storage facilities.

Regulatory Risk - Management believes that fair regulatory treatment is crucial to maintaining its financial stability, including its ability to attract capital. Principal regulatory risks for the Company relate to the relative frequency and magnitude of rate increases sought in contested retail rate filings. Regulatory lag and 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. When the Company's regulated earnings are capped at an allowed rate of return and certain costs that are disallowed for rate setting purposes reduce the earnings potential, the Company is at risk of not achieving its allowed rate of return on equity for its operations as a whole. The VPSB approved a retail rate increase of 9.09 percent in 2006 to be effective January 1, 2007. Principal reasons for the rate increase request include forecasted higher replacement energy costs upon expiration of the Morgan Stanley Contract on December 31, 2006, increased energy costs for uncovered load obligations and a forecasted increase in transmission expense.

Electric rates in Vermont are currently among the lowest in the New England region due in large part to Vermont utilities' relatively low cost, long-term contracts with VYNPC and Hydro Quebec. Since 2001, the Company's need for rate relief has been modest, reflecting only scheduled rate increases of 1.9 percent in 2005 and 0.9 percent in 2006 under the 2003 Rate Plan. The 9.09 percent retail rate increase that was approved for the Company for 2007, while significant, is below that of many other utility companies in Vermont and New England.

In December 2006, the VPSB approved an Alternative Regulation Plan (the "2007 Alternative Regulation Plan") for the Company effective February 1, 2007 and continuing for a three-year period ending January 31, 2009 (unless extended by approval of the VPSB). The 2007 Alternative Regulation Plan includes a power supply adjustment mechanism and an earnings sharing mechanism. The 2007 Alternative Regulation Plan is described in more detail below under "Rates."

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.

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.

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 23.3, 23.5, and 24.1 percent of the Company's retail MWh sales in 2006, 2005, and 2004, respectively, and 15.0, 15.3, and 16.4 percent of the Company's retail operating revenues in 2006, 2005, and 2004, respectively. No other retail customer accounted for more than one percent of the Company's revenue in any year.

Company revenues from sales of electricity to IBM decreased $1.1 million in 2006 when compared with 2005. Company revenue from sales of electricity to IBM decreased by approximately $95,000 in 2005 compared with 2004. Our operating results are not adversely impacted by reductions in sales to IBM because IBM's retail rates have recently been below wholesale market prices. We believe, based on a number of projected variables, that a hypothetical shutdown of the IBM facility, inclusive of the tertiary effects on commercial and residential customers, may necessitate a modest retail rate increase. The amount of such an increase would change materially as a result of any significant reductions in energy prices or increases in retail rates paid by IBM.

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, income on plan assets and, for our postretirement health care plan, health care cost trends. The Company contributed approximately $3.0 million, $2.0 million, and $2.2 million to its defined benefit plans during 2006, 2005, and 2004, respectively, and we expect to contribute approximately $2.7 million during 2007 and in future years.

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. This 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 is expected to reduce the rate at which postretirement healthcare expenses grow in the future.

The adoption of SFAS 158 for the year ended December 31, 2006 affected the Company's consolidated financial statements in the following ways. First, the previously recognized amounts of Accumulated Other Comprehensive Income were reduced to zero. Second, recognition of the total pension funding obligation created a regulatory asset. The following table summarizes the effects of the adoption of SFAS 158.

in thousands	December 31 2005	2006 Activity	SFAS 158 and regulatory reclassification	December 31 2006
Prepaid pension	$ 2,170	$ 1,623	$ (3,793)	$ -
	-	-	11,789	11,789

Regulatory asset FAS 158 pension funding obligation offset				
Deferred tax asset - federal	3,271	(1,749)	2,459	3,982
Deferred tax asset - state	868	(464)	653	1,057
Accumulated other comprehensive income	3,263	(3,074)	(188)	-
Minimum pension funding liability	(5,486)	5,486	-	-
Total pension funding obligation	-	(317)	(12,116)	(12,433)
SERP liability	(3,897)	(202)	4,099	-
Post retirement health care liability	(832)	493	338	-
Deferred tax liability - federal	(695)	(520)	(2,561)	(3,776)
Deferred tax liability - state	(184)	(138)	(680)	(1,002)

In 2004 and 2005, a reduction in the pension plan's discount rate was primarily responsible for increasing the OCI charge and related net liability by $566,000 and $910,000, respectively. The 2004 and 2005 OCI charges had only an indirect effect on net income by adjusting the amount of equity used in the allowed rate of return on equity calculation.

Customer Service Quality - The Company has agreed to customer service performance requirements that impose penalties up to approximately $750,000 in the event that the Company does not achieve certain goals. The Company typically exceeds the measurements, but in 2006 fell short on three goals due to extreme weather conditions, two unusual safety events and measurement protocol issues in our customer survey. Nevertheless, our performance fell well within the bandwidth that avoids financial penalties. The Company continues to enhance its use of technology to improve its performance and does not expect its measurements to fall below the prescribed penalty limits.

Weather - The Company periodically uses weather insurance to mitigate some of the risk of lost electricity sales caused by unfavorable weather conditions. The Company did not procure coverage for 2006 or 2005 because forward energy prices approximated average retail rate levels.

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 2006	2005	2004
	(In thousands, except per share data)		
Revenues			
Retail and other revenues	$ 213,833	$ 217,562	$ 207,922
Wholesale revenues	26,643	28,298	22,652
Total operating revenues	240,476	245,860	230,574
Operating expenses-Power Supply:			
Purchases from others	133,596	143,512	137,503
Company-owned generation	6,880	6,477	6,516
Other operating	28,898	24,751	19,295
Transmission	16,299	16,453	15,656
Maintenance	10,972	11,247	9,746
Depreciation and amortization	14,370	15,074	13,931
Taxes other than income	6,841	6,589	6,687
Income taxes	6,499	5,676	5,762
Total operating expenses	224,355	229,779	215,096
Operating income	16,121	16,081	15,478
Other income			
Equity in earnings of affiliates and non-utility operations	2,564	1,585	1,232
Allowance for equity funds used during construction	106	29	449
Other income	412	268	714
Expense of proposed merger	(1,621)	-	-
Other deductions	(238)	(157)	(308)
Total other income	1,223	1,725	2,087
Interest charges			
Long-term debt	6,806	6,534	6,534
Other	655	244	257
Allowance for borrowed funds used during construction	(48)	(18)	(285)
Total interest charges	7,413	6,760	6,506
Income from continuing operations	9,931	11,046	11,059
Income from discontinued operations, net	192	134	525
Net income applicable to common stock	$ 10,123	$ 11,180	$ 11,584
Earnings per share			
Basic earnings per share-continuing operations	$ 1.88	$ 2.12	$ 2.18
Basic earnings per share-discontinued operations	0.04	0.03	0.10
Basic earnings per share	$ 1.92	$ 2.15	$ 2.28
Diluted earnings per share-continuing operations	$ 1.85	$ 2.09	$ 2.10
Diluted earnings per share-discontinued operations	0.04	0.03	0.10
Diluted earnings per share	$ 1.89	$ 2.12	$ 2.20
Cash dividends declared per share	$ 1.12	$ 1.00	$ 0.88
Weighted average common shares outstanding-basic	5,270	5,195	5,083
Weighted average common shares outstanding-diluted	5,348	5,285	5,254

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

GREEN MOUNTAIN POWER CORPORATION **Consolidated Statements of Cash Flows**	**For the Years Ended December 31**		
	2006	**2005**	**2004**
Operating Activities:		(in thousands)	
Net income	$ 10,123	$ 11,180	$ 11,584
Less net income from discontinued operations	192	134	525
Income from continuing operations	9,931	11,046	11,059
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	14,370	15,074	13,931
Dividends from associated companies	1,017	1,273	863
Equity in undistributed earnings of associated companies	(2,268)	(1,318)	(880)
Allowance for funds used during construction	(154)	(47)	(733)
Amortization of deferred purchased power costs	2,896	2,581	318
Deferred income tax expense, net of investment tax credit amortization	(1,411)	(2,563)	3,699
Deferred purchased power costs	(4,607)	(2,023)	(667)
Deferred regulatory revenues	5,678	2,778	(2,970)
Environmental and conservation deferrals, net	(1,109)	(312)	(1,041)
Gain on sale of property	-	-	(402)
Share-based compensation	1,816	1,354	1,244
Changes in:			
Accounts receivable and accrued utility revenues	1,562	(1,705)	(1,120)
Prepayments, fuel and other current assets	(3,239)	(950)	(418)
Accounts payable and other current liabilities	804	470	1,567
Accrued income taxes payable and receivable	(5,367)	6,031	(2,069)
Other	(1,968)	(2,255)	1,010
Net cash provided by continuing operations	17,950	29,434	23,391
Operating cash flows from discontinued operations	192	337	525
Net cash provided by operating activities	18,142	29,771	23,916
Investing Activities:			
Construction expenditures	(18,464)	(16,978)	(18,577)
Restriction of cash for renewable energy investments	1,024	(973)	(354)
Proceeds from sale of property	-	-	648
Investment in associated companies	(17,083)	-	(4,579)
Distributions from associated companies	646	189	314
Investment in nonutility property	(228)	(210)	(338)
Net cash used in investing activities	(34,105)	(17,972)	(22,886)
Financing Activities:			
Proceeds from bond issuance	30,000	-	-
Payments on capital lease	(382)	(187)	-
Issuance of common stock	1,788	1,373	1,885
Reduction in long-term debt and term loan	(14,000)	-	-
Short-term debt	-	(3,000)	2,500
Cash dividends	(5,912)	(5,205)	(4,481)
Net cash used in financing activities	11,494	(7,019)	(96)
Net increase (decrease) in cash and cash equivalents	(4,469)	4,780	934

Cash and cash equivalents at beginning of period		6,500		1,720		786
Cash and cash equivalents at end of period	$	2,031	$	6,500	$	1,720
Supplemental Disclosure of Cash Flow Information:						
Cash paid for:						
Interest	$	6,599	$	6,700	$	6,691
Income taxes		10,211		2,221		3,043
Non-cash construction additions		5,119		1,229		1,563
The accompanying notes are an integral part of these consolidated financial statements.						

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	At December 31, 2006	2005
ASSETS	(In thousands)	
Utility plant		
Utility plant, at original cost	$ 362,970	$ 347,947
Less accumulated depreciation	127,704	122,924
Utility plant, net of accumulated depreciation	235,266	225,023
Property under capital lease	4,060	4,369
Construction work in progress	7,666	7,519
Total utility plant, net	246,992	236,911
Other investments		
Associated companies, at equity	27,768	10,036
Other investments	9,494	10,627
Total other investments	37,262	20,663
Current assets		
Cash and cash equivalents	2,031	6,500
Accounts receivable, less allowance for doubtful accounts of $401 and $484	17,640	19,594
Accrued utility revenues	7,683	7,291
Fuel, materials and supplies, average cost	6,690	6,360
Power supply derivative asset	468	15,342
Power supply regulatory asset	4,213	7,791
Prepayments and other current assets	4,344	1,434
Income tax receivable	1,187	-
Total current assets	44,256	64,312
Deferred charges		
Demand side management programs	4,376	5,835
Purchased power costs	3,683	1,812
Pine Street Barge Canal	12,070	12,861
Power supply regulatory asset	18,313	22,344
Pension funding regulatory asset	11,789	-
Other regulatory assets	5,954	5,809
Other deferred charges	1,038	3,068
Total deferred charges	57,223	51,729
Non-utility		
Property and equipment	-	246
Other assets	229	407
Total non-utility assets	229	653
Total assets	$ 385,962	$ 374,268

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	At December 31, 2006	2005
CAPITALIZATION AND LIABILITIES	(In thousands except share data)	
Capitalization		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 6,131,489 and 6,060,962)	$ 20,438	$ 20,203
Additional paid-in capital	82,824	81,271
Retained earnings	40,075	35,864
Accumulated other comprehensive income	-	(3,263)
Treasury stock, at cost (827,639 shares)	(16,701)	(16,701)
Total common stock equity	126,636	117,374
Long-term debt, less current maturities	109,000	79,000
Total capitalization	235,636	196,374
Capital lease obligation	3,562	3,944
Current liabilities		
Current portion of long term debt	-	14,000
Accounts payable, trade and accrued liabilities	18,575	14,196
Accounts payable to associated companies	1,338	1,483
Accrued taxes	1,423	5,603
Power supply derivative liability	4,213	7,791
Power supply regulatory liability	468	15,342
Customer deposits	920	1,052
Interest accrued	1,491	1,137
Other	2,791	2,552
Total current liabilities	31,219	63,156
Deferred credits		
Power supply derivative liability	18,313	22,344
Accumulated deferred income taxes	28,989	28,092
Unamortized investment tax credits	1,998	2,280
Pine Street Barge Canal cleanup liability	4,535	6,096
Accumulated cost of removal	21,494	21,105
Deferred compensation	5,485	8,213
Deferred regulatory revenues	6,260	582
Other regulatory liabilities	7,738	6,485
Minimum pension liablity	12,433	5,486
Other deferred liabilities	5,759	7,737
Total deferred credits	113,004	108,420
COMMITMENTS AND CONTINGENCIES, Note 3		
Non-utility		
Net liabilities of discontinued segment	2,541	2,374
Total non-utility liabilities	2,541	2,374
Total capitalization and liabilities	$ 385,962	$ 374,268

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

Consolidated Statements of Changes in Stockholders' Equity and Comprehensive Income	Common Stock				Accumulated		
	Shares	Amount	Paid-in Capital	Retained Earnings	Other Comprehensive Income	Treasury Stock	Total Common Equity
(In thousands except share data)							
BALANCE, December 31, 2003	**5,033,215**	**$ 19,536**	**$ 76,081**	**$ 22,786**	**$ (1,787)**	**$ (16,701)**	**$ 99,915**
Common stock issuance:							
Stock options and grants	107,264	358	2,771	-	-	-	3,129
Net income	-	-	-	11,584	-	-	11,584
Other comprehensive loss	-	-	-	-	(566)	-	(566)
Common stock dividends-$0.88 per share	-	-	-	(4,481)	-	-	(4,481)
BALANCE, December 31, 2004	**5,140,479**	**19,894**	**78,852**	**29,889**	**(2,353)**	**(16,701)**	**109,581**
Common stock issuance:							
Stock options and grants	92,844	309	2,419	-	-	-	2,728
Net income	-	-	-	11,180	-	-	11,180
Other comprehensive loss	-	-	-	-	(910)	-	(910)
Common stock dividends-$1.00 per share	-	-	-	(5,205)	-	-	(5,205)
BALANCE, December 31, 2005	**5,233,323**	**20,203**	**81,271**	**35,864**	**(3,263)**	**(16,701)**	**117,374**
Common stock issuance:							
Stock options and grants	70,527	235	1,553				1,788
Net income				10,123	-		10,123
Other comprehensive income					3,263		3,263
Common stock dividends-$1.12 per share				(5,912)			(5,912)
BALANCE, December 31, 2006	**5,303,850**	**$ 20,438**	**$ 82,824**	**$ 40,075**	**$ -**	**$ (16,701)**	**$ 126,636**

Consolidated Statements of Comprehensive Income	For the years ended December 31,		
	2006	2005	2004
	In thousands		
Net income	$ 10,123	$ 11,180	$ 11,584
Minimum pension liability adjustment, net of applicable income taxes	3,263	(910)	(566)
of $2,223 expense, $620 benefit and $391 benefit, respectively			
Other comprehensive income	$ 13,386	$ 10,270	$ 11,018
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 generates, 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. Most 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 92,000 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 ("VYNPC").

The results of 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 the Company's unregulated water heater program is as follows:

	For the Years ended December 31,		
In thousands	**2006**	**2005**	**2004**
Revenue	$ 921	$ 941	$ 961
Expense	661	652	594
Net Income	$ 260	$ 289	$ 367

The Company accounts for its investments in VYNPC, Vermont Electric Power Company, Inc. ("VELCO"), Vermont Transco LLC (“Transco”), 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 effect 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 and deferred regulatory revenue, pension and postretirement 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 Company's operating results are subject to an earnings cap equal to its allowed rate of return on equity on investments allowed to be recovered by the VPSB, reduced by amounts normally excluded for purposes of setting rates. Nearly all of the Company's continuing operations are treated for ratemaking purposes as regulated operations. The Company's 2006 and 2005 return on equity was 8.35 and 9.85 percent, respectively, reflecting the exclusions mentioned above.

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. Revenues in excess of allowed costs are deferred and appear in the Company's financial statements under the caption "Deferred regulatory revenues". 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.

Regulatory assets and liabilities	**Total At December 31, 2006**	**2005**	**Amortizable 2006 balances included in rates in 2007**
		(in thousands)	
Regulatory assets:			
Demand-side management programs	$ 4,376	$ 5,835	$ 4,376
Purchased power costs	3,683	1,812	3,683
Pine Street barge canal	12,070	12,861	6,732
Derivative liability regulatory assets	22,526	30,135	-
Pension funding regulatory asset	11,789	-	-
Other regulatory assets	5,954	5,809	3,559
Total regulatory assets	60,398	56,452	18,350
Regulatory liabilities:			
Accumulated cost of removal	21,494	21,105	21,494
Deferred regulatory revenues	6,260	582	582
Derivative asset regulatory liability	468	15,342	-
Other regulatory liabilities	7,738	6,485	5,855
Other deferred liablilities	5,759	7,737	3,062
Total regulatory liabilities	41,719	51,251	30,993
Regulatory assets net of regulatory liabilities	$ 18,679	$ 5,201	$ (12,643)

The derivative regulatory assets and liabilities represent the value of certain power supply contracts and interest rate swaps 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 Derivative Instruments.

The Company has historically deferred and amortized uninsured replacement power costs associated with significant unscheduled outages at the Vermont Yankee nuclear power plant owned by Entergy Nuclear Vermont Yankee LLC ("ENVY') and other extraordinary losses. The Company also had the ability to defer and amortize extraordinary costs associated with natural disaster, severe storms costs or significant loss of load under the Company's 2003 rate plan, when such costs are deemed probable of recovery. Such deferral and amortization require VPSB approval. The Company recovers these costs from customers over periods determined by the VPSB in a future rate filing. Under the 2007 Alternative Regulation Plan, 90 percent of extraordinary power costs in excess of $300,000 per quarter will be recovered through the Plan's power supply adjustment mechanism (the "power supply adjustor")

Other regulatory assets totaled $5.9 million and $5.8 million at December 31, 2006 and 2005, 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. Most of these assets are amortized over a period of between five and seven years.

Other regulatory liabilities totaled $7.7 million and $6.5 million at December 31, 2006 and 2005, respectively. It consisted of amounts received from VYNPC that were subject to a regulatory deferral order, a settlement from an interest rate swap, and regulatory tax liabilities.

The Company continues to believe, based on current regulatory circumstances, that the use of regulatory accounting under SFAS 71 remains appropriate and that its regulatory assets are probable of recovery. 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 pursuant to the adoption by the Company of SFAS 143.

In September 2006, FASB issued SFAS 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements Nos. 87, 88, 106 and 132(R)," to be effective December 31, 2006. SFAS 158 requires an employer to recognize in its balance sheet the funded status of its benefit plans. This is measured as the difference between plan assets at fair value and the benefit obligation. Employers are to record previously unrecognized gains and losses, prior service costs, and the remaining transition asset or obligation as a result of adopting SFAS 87 and SFAS 106 as accumulated other comprehensive income ("OCI") or as a regulatory asset reflective of the recovery mechanism for pension and OPEB costs in the utility's jurisdictions.

The following table summarizes the effect of adoption of SFAS 158 on the Company's consolidated financial statements.

in thousands	**December 31 2005**	**2006 Activity**	**SFAS 158 and regulatory reclassification**	**December 31 2006**
Prepaid pension	$ 2,170	$ 1,623	$ (3,793)	$ -
Regulatory asset FAS 158 pension funding obligation offset	-	-	11,789	11,789
Deferred tax asset - federal	3,271	(1,749)	2,459	3,982
Deferred tax asset - state	868	(464)	653	1,057
Accumulated other comprehensive income	3,263	(3,074)	(188)	-
Minimum pension funding liability	(5,486)	5,486	-	-
Total pension funding obligation	-	(317)	(12,116)	(12,433)

SERP liability	(3,897)	(202)	4,099	-
Post retirement health care liability	(832)	493	338	-
Deferred tax liability - federal	(695)	(520)	(2,561)	(3,776)
Deferred tax liability - state	(184)	(138)	(680)	(1,002)

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; and non-performing loans. The Company recognized income of $.04 per share in 2006 and $.03 per share in 2005 from Discontinued Operations primarily as a result of the realization of tax capital loss carryforwards. Income in 2004 reflects 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, 2006, 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,	**Approximate Average depreciable life in years**	**2006**	**2005**
		In thousands	
Property, Plant and Equipment:			
Intangible, FERC Licenses and Software	13	$ 8,501	$ 11,162
Generation	41	77,445	73,413
Transmission	39	40,931	40,311
Distribution	37	204,235	193,261
General, including transportation	18	31,858	29,800
Total Plant in Service		362,970	347,947
Accumulated Depreciation and Amortization		(127,704)	(122,924)
Net Plant in Service		235,266	225,023
Capital Lease		4,060	4,369
Construction Work in Progress		7,666	7,519
Total Utility Plant, net		$ 246,992	$ 236,911

Depreciation and Amortization. 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 3.1 percent during 2006, 3.4 percent during 2005, and 3.3 percent during 2004 of total depreciable property, reflecting the impact of a new depreciation schedule adopted as a result of a study that was completed in 2005 and implemented in 2006.

The Company amortizes nearly all of its intangible and regulatory assets using the straight-line method based on the cost and amortization period approved by the VPSB for the intangible property outstanding at the beginning of the year. Amortization expense totaled $3.6 million, $3.8 million, and $3.3 million for 2006, 2005 and 2004, respectively.

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 is required to set aside $302,000, included in Other Investments, as of December 31, 2006, 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 recognizes deferred regulatory 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. Revenues in excess of allowed costs, or, earnings in excess of the earnings limitation, are deferred and appear in the Company's financial statements under the caption "Deferred regulatory revenues". The Company deferred regulatory revenues of $5.7 million and $582,000 during 2006 and 2005, respectively, and recognized $3.0 million in deferred regulatory revenues during 2004. See Note H 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	Accounts Charged Off	Balance at End of Period
2006	$ 484	$ 381	$ 464	$ 401
2005	620	308	444	484
2004	691	549	620	620

Earnings Per Share. Basic earnings per share ("EPS") is calculated by dividing net income 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 are 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.

Stock-Based Compensation

During the year ended December 31, 2000, the Company granted options for 335,300 shares under its 2000 Stock Incentive 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. Prior to the adoption of SFAS 123R, the Company followed the prospective method of accounting for stock-based compensation under SFAS 148, *Accounting for Stock-Based Compensation,* 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. Stock options granted during 2003 have been expensed and no stock options have been granted after 2003.

Pro-forma net income

	For the years ended December 31,					
		2006		**2005**		**2004**
In thousands, except per share amounts						
Net income reported	$	10,123	$	11,180	$	11,584
Pro-forma net income	$	10,123	$	11,180	$	11,503
Net income per share						
As reported-basic	$	1.92	$	2.15	$	2.28
Pro-forma basic	$	1.92	$	2.15	$	2.26
As reported-diluted	$	1.89	$	2.12	$	2.20
Pro-forma diluted	$	1.89	$	2.12	$	2.19
Stock compensation included in results, net of tax	$	1,031	$	806	$	740
Fair value of all stock compensation		1,031		806		821

Major Customers and Other Concentration Risks. The Company has one major retail customer, International Business Machines Corporation ("IBM"), that accounted for 23.3 percent, 23.5 percent, and 24.1 percent of retail MWh sales, and 15.0 percent, 15.3 percent and 16.4 percent of the Company’s retail operating revenues in 2006, 2005 and 2004, respectively.

We believe that a hypothetical shutdown of the IBM facility may necessitate a modest retail rate increase for all remaining customers, including secondary and tertiary impacts of such a shutdown on other customer sales, because the Company could sell some of the contracted power supply resources into the wholesale market at prices in excess of current rates charged to IBM. The amount of such an increase would change materially as a result of any significant reductions in energy prices or increases in retail rates paid by IBM.

Our material power supply contracts are principally with Hydro Quebec and VYNPC. These contracts are expected to meet approximately 75 to 80 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. The JP Morgan Contract is expected to provide an additional 10 percent of our anticipated annual demand requirements during the next five years.

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:

	At December 31,							
	2006				**2005**			
In thousands		**Calculated Fair Value**		**Amount carried on balance sheet**		**Calculated Fair Value**		**Amount carried on balance sheet**
Long-Term Debt, net,(Note F)	$	108,360	$	109,000	$	76,851	$	79,000
Derivatives, net		(22,058)		(22,058)		(14,793)		(14,793)
Current portion of long-term debt		-		-		14,080		14,000

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, *Accounting for Derivative Instruments and Hedging Activities*, as amended, established 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.

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.

The Morgan Stanley Contract was used to hedge against increases in fossil fuel prices. Morgan Stanley purchased a portion of the Company's power supply resources at index (fossil fuel resources) or specified (i.e., contracted resources) prices and then sold to us at a fixed rate to serve pre-established load requirements. This contract allowed management to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The Morgan Stanley Contract expired December 31, 2006.

In 2006, the Company entered into a power supply agreement with JP Morgan Ventures Energy Corporation Contract (“JP Morgan Contract”) to hedge against fossil fuel price increases. This contract is a derivative but meets the exception for a normal purchase and sale contract, and therefore does not require the recording of an asset or liability. The JP Morgan Contract begins January 1, 2007 and ends on December 31, 2010.

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 a 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 Company has other less significant derivative positions. Forward sales contracts for the months of March and April, 2007 were made to capture forward energy prices that were high by historical standards. Interest rate swaps were used to hedge against rising interest rates for the issue of new bonds in 2006 and 2007.

The table below presents the Company's 9701 agreement and other derivatives. Actual results may differ materially from the table illustration.

Derivatives	**At December 31, 2006 Fair Value (in thousands)**
Interest rate swap	$ 193
Power supply swaps	(1,918)
9701 agreement	(20,608)
Forward sale contracts	275
	$ (22,058)

The table below presents assumptions used to estimate the fair value of derivatives, including the 9701 agreement and power supply swaps, forward sales contracts, and the remaining interest rate swap. 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**
Interest rate swap	Deterministic	n/a	n/a	n/a	2007
9701 agreement	Black-Scholes	4.4%	29%-10%	$93	2015
Forward sale contracts	Deterministic	5%	n/a	$70	2007
Power supply Swaps	Deterministic	4.8-5.1%	n/a	$92	2007-2009

At December 31, 2006, the Company had a total power supply derivative liability of $22.5 million reflecting the fair value of the 9701 agreement and power supply swaps, and a derivative asset of approximately $468,000, reflecting the fair value of the interest rate swap and the forward sale contracts. Corresponding regulatory assets and regulatory liabilities total $22.5 million and $468,000, respectively. Amounts due during 2007 are classified in current assets and current liabilities.

At December 31, 2005, the Company had a power supply derivative liability of $30.1 million reflecting the fair value of the 9701 agreement, and a power supply derivative asset of $15.3 million, reflecting the $15.1 million fair value of the Morgan Stanley Contract and the remaining asset attributable to the forward sale contracts. Corresponding regulatory assets and regulatory liabilities total $30.1 million and $15.3 million, respectively. Amounts due during 2006 were classified in current assets and current liabilities.

In March 2006, the Company entered into an interest rate swap relating to the Company's 2006 issuance of first mortgage bonds to mitigate the risk of rising interest rates. Approximately one-half of the new $30 million first mortgage bonds in 2006 was covered. The interest rate swap was settled on August 2, 2006, with a final gain on settlement of approximately $600,000, which has been recorded as a regulatory liability and will be amortized over the life of the bond issue as a component of interest expense.

In December 2006, the Company entered into a second interest rate swap relating to the Company's anticipated issuance of 2007 first mortgage bonds. Approximately $15 million of the $20 million first mortgage bonds proposed for 2007 was covered. The interest rate swap is still outstanding and has a fair value of $193,000 as of December 31, 2006. The final settlement will be amortized over the life of the bond issue as a component of interest expense.

Other Comprehensive Income. Prior to adoption of SFAS 158, certain negative scenarios and unfavorable market conditions (asset returns lower than expected, reductions in discount rates, and liability experience losses) caused the Pension Plan's accumulated benefit obligation ("ABO") to exceed the fair value of Pension Plan assets as of the measurement date and resulted in an unfunded minimum pension liability. Since the minimum liability exceeded the accrued benefit cost, an additional minimum pension liability had 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. The Company has recorded other comprehensive losses reflecting additional minimum pension liabilities relating to qualified and non-qualified plans. During 2004, due principally to a decline in the discount rate assumption used for pension calculations, we recorded an increase in other comprehensive loss of $566,000, net of $391,000 income tax. During 2005, due principally to a decline in the discount rate assumption used for plan calculation, we recorded an increase in other comprehensive loss of $910,000, net of $620,000 income tax.

For the year ending December 31, 2006, the Company adopted SFAS No. 158, Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R). In connection with the adoption, the minimum pension fund liability was eliminated.

Recent Accounting Pronouncements.

Accounting pronouncements adopted for years ending 2005 and 2004:
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.

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.

The Company was able to conclude that the benefits provided by the plan were actuarially equivalent to Medicare Part D under the Act, and was able 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"). 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 impacts annual net periodic cost in 2005 and beyond.

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 Company estimates its tax deduction on qualified production activities approximates $82,000.

As of December 31, 2005, the Company adopted FIN 47, which clarified that a legal obligation associated with the retirement of a long-lived asset whose timing and/or method of settlement are conditional on a future event is within the scope of SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under FIN 47, the Company is required to record liabilities associated with its conditional asset retirement obligation (“ARO”) at their estimated fair values if those fair values can be reasonably estimated.

At December 31, 2005, the Company measured its conditional AROs at fair value using the methodology prescribed by FIN 47 and recorded a resulting regulatory asset of approximately $344,000 under SFAS No. 71. During 2006, the Company recorded an additional $386,000 liability.

Accounting pronouncements adopted for year ending 2006:
In December 2004, the FASB issued SFAS No. 123(Revised), "Share-Based Payments," which replaces SFAS No. 123. 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 is based on the grant date fair value of the award. The Company used the fair value method for share-based payment awards for grants made after January 1, 2003. The Company adopted No. 123 (Revised) as of January 1, 2006. See Note C, Common Stock Equity and Stock Award Plans for effects on the financial statements of the Company.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)” (“SFAS 158”). SFAS 158 requires company plan sponsors to display the net over- or under-funded position of a defined benefit postretirement plan as an asset or liability, with any unrecognized prior service costs, transition obligations or actuarial gains/losses reported as a component of other comprehensive income in shareholders’ equity, unless the amount will be recoverable under SFAS 71 for regulated utilities, in which case it could be recorded as a regulatory asset. The provisions of SFAS 158 are effective for fiscal years ending after December 15, 2006. The Company has recorded a pension funding regulatory asset for $11.8 million and a total unfunded pension obligation for $12.4 million.

Accounting pronouncements considered for future periods:
In June 2006, the FASB issued FIN-48**,** Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109, effective for fiscal years beginning after December 15, 2006. This interpretation clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. The effects of the Company’s adoption of FIN-48 on its results of operations, cash flow or financial position are currently under consideration. The Company anticipates that this new standard will not have a material impact on our financial condition, results of operations or cash flows.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, “Fair Value Measurements” (“SFAS No. 157”). SFAS No. 157 redefines fair value as “the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.” SFAS No. 157 establishes a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. We will implement SFAS No. 157 as of January 1, 2008, applying the provisions retrospectively for derivative accounting and prospectively for all other valuations. We are currently evaluating the impact adoption may have on our financial condition, results of operations and cash flows.

In February 2007 the FASB issued Statement of Financial Accounting Standards No. 159 The Fair Value Option for Financial Assets and Financial Liabilities, Including an amendment of FASB Statement No. 115. This Statement permits entities to choose to measure many financial instruments and certain other items at fair value. The objective of the standard is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This Statement is expected to expand the use of fair value measurement, which is consistent with the Board’s long-term measurement objectives for accounting for financial instruments. This Statement is effective as of the beginning of an entity’s first fiscal year that begins after November 15, 2007. The Company will implement this statement as of January 1, 2008 and we are currently evaluating the effects of adoption.

B. INVESTMENTS IN ASSOCIATED COMPANIES
The Company accounts for investments in the following associated companies by the equity method:

	Percent Ownership at December 31,		Investment in Equity at December 31,	
	2006	2005	2006	2005
			(In thousands)	
VELCO-common	29.17%	29.17%	$ 7,054	$ 7,048
VELCO-preferred	30.00%	30.00%	52	68
Total VELCO			7,106	7,116
Transco LLC	21.90%	-	17,843	-
VYNPC- Common	33.60%	33.60%	1,615	1,601
New England Hydro Transmission-Common	3.18%	3.18%	436	485
New England Hydro Transmission Electric-Common	3.18%	3.18%	768	834
Total investment in associated companies			$ 27,768	$ 10,036

VELCO and Transco. In June 2006, VELCO's Board of Directors approved a plan to transfer substantially all of VELCO's business to Transco, a Vermont limited liability company. On June 30, 2006, VELCO's assets were transferred to Transco in exchange for 2.4 million Class A Membership Units and Transco's assumption of VELCO's debt. VELCO and its employees will manage the operations of Transco under an operating agreement that includes the Company, Central Vermont Public Service Corporation and most of Vermont's electric utilities. Transco is operating under Amended and Restated Three Party Agreements that include the Company, Central Vermont Public Service Corporation, VELCO and Transco. VELCO has a 30.8 percent ownership interest in Transco.

The Company invested $17.1 million in Transco during 2006. These investments entitled the Company to receive a 21.9 percent equity ownership interest represented by Class A Membership Units in Transco that will receive an 11.5 percent rate of return. Since results are accounted for as a regulated business for Vermont rate setting, the return to the Company is capped at our allowed rate of return.

Transco owns and operates the transmission system in Vermont over which bulk power is delivered to all electric utilities in the state. The Company plans to make capital investments of approximately $8.4 million in 2007 in Transco in support of various transmission projects. The Company is evaluating opportunities to invest an additional $19 million in Transco for similar purposes. The Company's capital contributions to Transco are based on, and consistent with, our original equity commitments to VELCO.

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

	2006
	(In thousands)
Net income	$ 5,527
Company's equity in net income	$ 1,011
Total assets	$ 292,707
Liabilities and long-term debt	214,101
Net assets	$ 78,606
Company's equity in net assets	$ 17,843

VELCO has entered into transmission agreements with the State of Vermont and other electric utilities including the Company, and under these agreements, VELCO and Transco bill all costs, including interest on debt and a fixed return on equity, to the State and others, including the Company, using Transco'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 and Transco's operating costs, including debt service costs.

Summarized unaudited financial information for VELCO (consolidated) follows:
At and for the years ended December 31,

		2006		2005		2004
				(In thousands)		
Net income	$	5,053	$	3,018	$	1,683
Company's equity in net income	$	1,841	$	877	$	472
Total assets	$	310,759	$	187,549	$	145,632
Liabilities and long-term debt		232,383		163,142		120,983
Net assets	$	78,376	$	24,407	$	24,649
Company's equity in net assets	$	24,949	$	7,116	$	7,199
Amounts due from (to) VELCO	$	1,791	$	1,596	$	(4,068)

2006 amounts include Transco

VELCO provided transmission services to the Company (reflected as transmission expenses in the accompanying Consolidated Statements of Income) amounting to $1.2 million in 2006, $1.6 million in 2005, and $12.3 million in 2004, respectively. Amounts decreased in 2006 and 2005 because ISO-NE now invoices the Company directly for transmission services. Previously, ISO-NE invoiced VELCO and VELCO invoiced the Company for those transmission services.

Included in the Company's retail and other revenues are construction services of approximately $8.8 million and $4.8 million billed to VELCO in 2006 and 2005, respectively.

Vermont Yankee Nuclear Power Corporation ("VYNPC"). The Company's ownership share of VYNPC is approximately 33.6 percent. The Company's entitlement to energy produced by the Vermont Yankee nuclear plant owned by Entergy Nuclear Vermont Yankee LLC ("ENVY") has been approximately 20 percent of plant production since the plant began operations. The Vermont Yankee plant received final approval for uprating from the Nuclear Regulatory Commission on March 2, 2006, resulting in a lower percentage for our entitlement to an increased plant production capability of approximately 17 percent.

The purchased power agreement between ENVY and VYNPC specifies that our percentage of energy output under VYNPC's contract with ENVY declines after the VY nuclear plant uprating is completed. The Company believes its share of the plant's output should be equivalent to the amount of power it received before the uprate process began. VYNPC and ENVY are discussing the calculations which depend upon determination of the pre-uprate capability of the plant, which is presently disputed. The Company estimates the potential impact of the differing methods of calculation could adversely affect power supply expense by up to $600,000 annually. In the event that the VY nuclear plant is derated in the future, then our rights to energy output could decline proportionately to such derating. If this were to occur, we estimate it would have a material adverse effect on our power supply costs. In this event we would seek recovery of these costs from the VPSB.

The Company is currently a party to a VPSB Docket that was opened to investigate whether the reliability of the increased nuclear plant output will be adversely affected by the operation of the plant's steam dryer. On September 18, 2006, the VPSB issued a ruling requiring ENVY to provide additional ratepayer protections that would make Vermont ratepayers whole in the event that VY must reduce power due to uprate-related steam dryer failure. Under the VPSB ruling, these protections will only apply to incremental replacement power costs incurred due under the terms of the Purchase Power Agreement ("PPA") between ENVY and VYNPC. The additional ratepayer protections are required to remain in effect through a period two months after the first refueling outage in which VY operates successfully with no steam dryer-related outages or derates. VY's next scheduled refueling outage is presently scheduled for early 2007.

ENVY requested reconsideration of the VPSB ruling. Reconsideration was denied and ENVY has appealed the decision to the Vermont Supreme Court.

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

		2006		2005		2004
				(In thousands)		
Earnings:						
Operating revenues	$	201,325	$	160,613	$	167,399
Net income applicable to common stock		749		660		538
Company's equity in net income	$	251	$	221	$	181
Total assets	$	157,880	$	153,132	$	151,542
Liabilities and long-term debt		153,079		148,371		146,747
Net Assets	$	4,801	$	4,761	$	4,795
Company's equity in net assets	$	1,615	$	1,601	$	1,612
Amounts due to VYNPC	$	3,129	$	3,077	$	3,324

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 J for further information concerning our long-term power contract with VYNPC.

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, 2006. The Company also funds an Employee Savings and Investment Plan ("ESIP") under which the Company may contribute shares of common stock. Under our ESIP plan, we match up to the first four percent of annual base salary and make an additional contribution of a half percent of base salary on a non-matching basis. Matching contributions are currently made in cash and immediately vest. The Company's matching and non-matching contributions for the years 2006, 2005 and 2004 were $530,000, $524,000 and $487,000, respectively.

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 previously 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, 2006, no shares were unissued under the 2000 Stock Plan. During the year ended December 31, 2000, the Company granted options for 335,300 shares 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. The Company discontinued granting stock options 2003.

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, 2006, approximately 116,000 shares have been issued under the 2004 Stock Incentive Plan. Effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(revised 2004), Share-Based Payment (“SFAS 123R”), using the Statement’s modified prospective application method. Prior to the adoption, the Company followed the provisions of FASB 123 and expensed the stock option grants. Accordingly, prior periods have not been restated.

All of the Company's stock-based compensation is based on grants of equity instruments and no liability awards have been granted. Unrestricted stock grants and deferred stock unit awards have been made only to employees, senior management and directors. Unrestricted stock grants vest immediately and are recognized as compensation expense based on the fair value of the awards at the grant date. During the years ended December 31, 2006 and 2005, the Company granted 14,862 shares and 14,450 shares of unrestricted stock to employees with a weighted average grant date fair value of $33.26 per share, and $29.87 per share, respectively.

Deferred stock unit awards are recognized as deferred compensation based on the fair value of the award at the grant date and charged ratably to expense over the required service period for each award, which generally equals the vesting period. Stock unit awards to senior management vest over a two-year service period, unless such senior management is retirement eligible. The stock unit awards for retirement eligible senior management are deemed vested and the applicable expense recognized over the retirement eligible vesting period. Stock unit awards may be deferred and earn the equivalent of dividends each quarter, which are then converted to share units, during the deferral period. No modifications of existing awards occurred. All shares issued for stock awards are new shares. Total compensation expense from all stock awards to directors, employees and senior management totaled $1.8 million, $1.4 million and $1.2 million for the years 2006, 2005 and 2004, respectively. The summary table of stock unit awards activity reflects all stock award compensation, but does not reflect the "retirement eligible" stock units as vested.

Stock awards	**Total Stock Awards**	**Vested Stock Awards Share units**	**Non-vested Stock Awards**	**Weighted Average Grant-date fair value**	**Shares returned for income tax withholding**	**Compensation cost recognized**
Outstanding at December 31, 2005	58,566	7,166	51,400	$ 27.39	-	$ -
Employee grants and dividend equivalents earned	14,862	14,862		33.26	4,872	494,527
Grants to officers and directors	52,870	-	52,870	29.07	311	1,415,805
Vested	-	41,900	(41,900)	27.84	-	
Forfeited	(3,333)		(3,333)	28.30		(94,324)
Issued	(58,215)	(58,215)	-	-	10,411	
Outstanding at December 31, 2006	64,750	5,713	59,037	$ 28.53	15,594	$ 1,816,008

Approximately $761,000 of unrecognized share-based compensation exists at December 31, 2006, with a weighted average accrual period of 8 months remaining. The amount capitalized as part of the cost of assets was approximately $12,000.

For the year ended December 31, 2006, cash received from the exercise of options totaled approximately $344,000 and the Company recognized a reduction in income tax liability of approximately $257,000. The adoption of SFAS 123R resulted in no incremental stock-based compensation expense and had no impact on net income, diluted earnings per share or cash flows from operating or financing activities for this same period.

Upon consummation of the proposed merger discussed under "Mergers and Acquisitions," all of the remaining unexercised stock options convert to shares, and any remaining unvested stock grants immediately vest.

The fair value of options granted in 2003 was $1.33 per share. The fair value was 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, 2006:

				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	85,100	3.6	6.05%	5	30.58	4.5%
2001	$ 16.78	5,900	4.7	5.25%	6	32.69	4.0%
2002	$ 18.03	26,700	5.4	4.50%	6.5	16.89	4.5%
Total	$ 10.64	117,700					

	Total Options	**Weighted Average Price**	**Range of Exercise Prices**	**Options Exercisable**	**Aggregate Intrinsic Value**	**Average Contractual Life in Years**
Outstanding at December 31, 2003	300,850	11.39	$ 7.90-$22.62	193,700		
Granted	-	-	-			
Exercised	89,650	12.11	$ 7.90-$20.96			
Forfeited	1,900	18.65	$ 17.54-$20.96			
Outstanding at December 31, 2004	209,300	$ 11.07	$ 7.90-$22.62	213,500		
Granted	-					
Exercised	62,500	$ 11.31	$ 7.90-$22.62			
Forfeited	200	$ 20.08	$ 17.54-$22.62			
Outstanding at December 31, 2005	146,600	$ 10.90	$ 7.90-$22.62	146,600		
Granted	-					
Exercised	28,900	$ 11.92	$ 7.90-$20.96		344,488	
Forfeited						
Outstanding at December 31, 2006	117,700	$ 10.64	$ 7.90-$18.95	117,700	$ 1,252,328	4.1

The following table presents a reconciliation of 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**		
	2006	**2005**	**2004**
		(in thousands)	
Net income before preferred dividends	$ 10,123	$ 11,180	$ 11,587
Preferred stock dividend requirement	-	-	3
Net income applicable to common stock	$ 10,123	$ 11,180	$ 11,584
Average number of common shares-basic	5,270	5,195	5,083

Dilutive effect of stock options	78	90	171
Average number of common shares-diluted	5,348	5,285	5,254

Common stock issuance from compensation programs during 2006 amounted to 85,662 shares. Of this amount, 28,900 shares were issued for exercised options, 49,362 shares were issued for employee stock grants and 7,400 shares were issued for grants to the Company’s Board of Directors.

Common stock issuance from compensation programs during 2005 amounted to 92,844 shares. Of this amount, 62,500 shares were issued for exercised options, 20,444 shares were issued for employee stock grants and 9,900 shares were issued for grants to the Company’s Board of Directors. Common stock issuance from compensation programs during 2004 amounts to 107,264 shares. Of this amount, 89,650 shares were issued for exercised options, 9,914 shares were issued for employee stock grants and 7,700 shares were issued for grants to the Company’s Board of Directors.

Appropriated Retained Earnings. The Company had appropriated retained earnings of $409,000 and $379,000 at December 31, 2005 and 2004, 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 $8.2 million of retained earnings were free of restrictions at December 31, 2006.

D. SHORT-TERM DEBT

Effective June 14, 2006, the Company has a five year revolving credit facility of $30 million with Sovereign Bank and Key Bank replacing the expired 364-day revolving credit agreement with Bank of America, joined by Sovereign Bank (“the Fleet-Sovereign Agreement”). The Sovereign/Key Bank revolving credit facility is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. This revolving credit facility does not include any material adverse change or material adverse effect clauses, subsequent to the effective date, as pre-conditions for borrowing under the facility. There was no balance outstanding at December 31, 2006.

Under the Fleet-Sovereign Agreement, there was no balance outstanding at December 31, 2005. There was no non-utility short-term debt outstanding at December 31, 2006.

E. LONG-TERM DEBT

On August 3, 2006, the Company closed on the first tranche of the new $30 million First Mortgage Bonds, 6.53% Series, due August 1, 2036 and received $11 million in funds. The funds were primarily used to partially fund additional capital investments by the Company in Transco. The second tranche of $19 million was received in December 2006 and repaid $14 million of First Mortgage Bonds and repaid short-term bank borrowings.

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 6.9 percent at December 31, 2006 and 7.0 percent at December 31, 2005. 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			At December 31,	
First Mortgage Bonds			**2006**	**2005**
Interest Rate	**Maturity**	**Annual Sinking Fund**	(In thousands)	
7.18%		-	$ -	$ 10,000

	Nov. 6, 2006			
7.05%	Dec. 15, 2006	-	-	4,000
6.04%	Dec. 1, 2017	6,000,000 begins 2011	42,000	42,000
6.70%	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
6.53%	Aug. 1, 2036	-	30,000	-
Total Long-term Debt Outstanding			109,000	93,000
Less Current Maturities (due within one year)			-	14,000
Total Long-term Debt, less current maturities			$ 109,000	$ 79,000

F. 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, 2006 and December 31, 2005, were as follows:

	At December 31, 2006	2005
	(In thousands)	
Deferred Tax Assets		
Contributions in aid of construction	$ 3,451	$ 2,629
Deferred compensation and postretirement benefits	2,466	5,664
Self insurance and other reserves	461	405
Deferred regulatory earnings	3,371	1,280
Cost of removal	8,710	8,553
Other	2,668	2,011
Derivatives	9,129	18,432
	$ 30,256	$ 38,974
Deferred Tax Liabilities		
Accelerated Tax Depreciation on Property	$ 41,480	$ 40,618
Demand side management	1,773	2,364
Deferred purchased power costs	1,568	818
Pine Street reserve	3,053	2,742
Investment in affiliates	1,051	697
Other	1,620	1,501
Derivative regulatory assets	9,129	18,432
	$ 59,674	$ 67,172
Net accumulated deferred income tax liability	$ 29,418	$ 28,198

The change in the net accumulated deferred income tax liability arises from the deferred income tax expense included in the income statement for the periods presented, the change in the tax effect of minimum pension funding liability changes, and the change in the tax effect of changes in income tax related regulatory assets and liabilities.

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

	For the Years ended December 31,		
	2006	**2005**	**2004**
	(In thousands)		
Current federal income taxes	$ 5,757	$ 6,326	$ 461
Current state income taxes	2,153	1,913	1,602
Total current income taxes	7,910	8,239	2,063
Deferred federal income taxes	(897)	(1,938)	3,843
Deferred state income taxes	(232)	(341)	140
Total deferred income taxes	(1,129)	(2,279)	3,983
Investment tax credits-net	(282)	(284)	(284)
Income tax expense	$ 6,499	$ 5,676	$ 5,762

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:

	For the Years ended December 31,		
	2006	**2005**	**2004**
	(In thousands)		
Income before income taxes and preferred dividends	$ 16,622	$ 16,856	$ 17,346
Federal statutory rate	35.0%	35.0%	35.0%
Computed "expected" federal income taxes	$ 5,818	$ 5,900	$ 6,071
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation basis difference	99	91	(149)
Dividends received deduction	(312)	(350)	(452)
Amortization of ITC	(282)	(284)	(284)
State tax	1,247	1,022	1,133
Excess deferred taxes	(60)	(60)	(123)
Energy credits and production deduction	(493)	(375)	(125)
Merger expenses	555	-	-
Other	(73)	(268)	(309)
Total federal and state income tax	$ 6,499	$ 5,676	$ 5,762
Effective combined federal and state income tax rate	39.1%	33.0%	34.5%

G. 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 a non-qualified retirement plan for certain employees. Benefits under the non-qualified plan are funded on a cash basis.

The Company also 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.

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 $3.0 million during 2006, $2.0 million during 2005 and $3.5 million during 2004. The Company currently plans to contribute approximately $2.0 million of additional funds during 2007.

During 2005, the Company increased its previously recognized minimum pension liability by $1.5 million to approximately $5.4 million, primarily as a result of a decrease in the pension plan discount rate assumption. Common equity decreased approximately $910,000, net of applicable income tax, through a charge to comprehensive income.

During 2006, the Company recorded a total unfunded pension obligation of approximately $12.4 million, primarily as a result of the adoption of SFAS 158. Common equity increased approximately $3.2 million, through a credit to comprehensive income upon the elimination of the minimum pension funding liability. The Company recorded a regulatory asset for the total unfunded pension obligation.

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, 2006 and 2005.

	2006	2005	2006	2005
		(In thousands)		
Change in projected benefit obligation:				
Projected benefit obligation prior year end	$ 45,419	$ 41,531	$ 19,012	$ 18,979
Service cost	1,400	1,229	277	306
Interest cost	2,479	2,371	991	1,013
Participant contributions	-	-	190	157
Plan change	70	549	-	-
Change in actuarial assumptions	-	-	-	-
Actuarial (gain) loss	(2,242)	1,880	(411)	(287)
Benefits paid	(2,116)	(1,964)	(1,447)	(1,156)
Administrative expense	(112)	(177)	-	-
Projected benefit obligation as of year end	$ 44,898	$ 45,419	$ 18,612	$ 19,012
Accumulated benefit obligation	$ 44,898	$ 45,419	$ 18,612	$ 19,012
Change in plan assets:				
Fair value of plan assets as of prior year end	$ 32,217	$ 29,930	$ 12,306	$ 11,672
Administrative expenses paid	(112)	(177)	-	-
Participant contributions	-	-	-	-
Employer contributions	3,369	2,011	-	250
Actual return on plan assets	4,113	2,417	1,491	508

Benefits paid		(2,116)		(1,964)		(191)		(124)
Fair value of plan assets as of year end	$	37,471	$	32,217	$	13,606	$	12,306
Funded status as of year end	$	(7,427)	$	(13,203)	$	(5,006)	$	(6,706)
Unrecognized transition obligation		-		-		1,968		2,296
Unrecognized prior service cost		1,426		1,566		(1,500)		(1,738)
Unrecognized net actuarial loss		5,696		9,910		4,199		5,317
Prepaid (accrued) benefits at year end	$	(305)	$	(1,727)	$	(339)	$	(831)

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

	For the years ended December 31,											
	Pension Plans						Other Postretirement Benefits					
		2006		2005		2004		2006		2005		2004
	(In thousands)											
Service cost	$	1,400	$	1,229	$	1,123	$	277	$	306	$	335
Interest cost		2,479		2,371		2,290		991		1,013		1,165
Expected return on plan assets		(2,621)		(2,454)		(2,285)		(977)		(967)		(857)
Amortization of transition asset		-		-		-		-		-		-
Amortization of prior service cost		210		227		205		(239)		(239)		(239)
Amortization of the transition obligation		-		-		-		328		328		328
Recognized net actuarial gain		480		351		267		192		177		338
Net periodic benefit cost	$	1,948	$	1,724	$	1,600	$	572	$	618	$	1,070

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 Plans		**Other Postretirement Benefits**	
	2006	**2005**	**2006**	**2005**
Weighted average assumptions as of year end:				
Discount rate	6.00%	5.50%	6.00%	5.50%
Expected return on plan assets	8.00%	8.25%	8.00%	8.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Medical inflation	-	-	9.25%	10.00%
Measurement date	12/31/2006	12/31/2005	12/31/2006	12/31/2005
Census date	1/1/2006	1/1/2005	1/1/2006	1/1/2005

Assumptions used in periodic cost measurement	**For the years ended December 31,**			
	Pension Plans		**Other Postretirement Benefits**	
	2006	**2005**	**2006**	**2005**
Weighted average assumptions as of year end:				
Discount rate	6.00%	5.75%	5.50%	5.75%
Expected return on plan assets	8.00%	8.25%	8.00%	8.25%

Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Current year trend	-	-	9.25%	10.00%
Ultimate year trend			5.00%	5.00%
Year of ultimate trend			2011	2011

For measurement purposes, a 9.25 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2006. 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 total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2006 by $152,000, or 12.0 percent. Decreasing the trend rate by one percentage point for all future years would decrease the total of the service and interest cost components of net periodic postretirement cost for 2005 by $117,000, or 9.2 percent.

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 combined plan assets be invested in equity securities, 30 percent of combined 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 8.00 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 Plans' Assets**			**Other Postretirement Benefit Assets**		
	For the years ended December 31,					
	2007 Target	**2006**	**2005**	**2007 Target**	**2006**	**2005**
Equity Securities	65.00%	53.06%	66.60%	65.00%	68.00%	65.00%
Debt Securities	23.00%	26.96%	18.71%	35.00%	29.00%	31.00%
Real Estate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other	0.00%	11.69%	6.31%	0.00%	3.00%	4.00%
Alternative investments	12.00%	8.29%	8.38%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

	Pension Plans Projected		**Other Postretirement Benefits Projected**	
In Thousands	**Contributions**	**Benefit payments**	**Contributions**	**Benefit payments**
2007	$ 2,403	$ 2,137	$ 963	$ 963
2008	2,700	2,644	1,000	999
2009	2,400	2,390	1,050	1,022
2010	2,300	2,286	1,050	1,065
2011	2,800	2,790	1,100	1,103
2012 through 2016	15,500	15,412	6,100	6,104

The Company maintains a 401(k) Savings Plan for substantially all employees. This savings plan provides for employee contributions up to specified limits. The Company matches employee pre-tax contributions up to 4 percent, and contributes an additional one-half percent each year made on a non-matching basis, of eligible compensation. The additional half percent contribution was added effective January 2004. The Company match is immediately vested. The Company's matching and non-matching contributions for the years 2006, 2005, and 2004 were $530,000, $524,000 and $487,000, respectively.

H. 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 J Long-Term Power Purchases.

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 $4.5 million, net of recoveries. 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 $12.1 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 began 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, 2006, as follows:

	Ownership Interest (In %)	Share of Capacity (In MW)	Share of Utility Plant (In thousands)	Share of Accumulated Depreciation (In thousands)
Highgate	33.8	67.6	$ 10,482	$ 5,753
McNeil	11.0	5.9	9,111	6,282
Stony Brook (No. 1)	8.8	31.0	11,390	10,066
Wyman (No. 4)	1.1	6.8	1,980	1,568
Metallic Neutral Return	59.4	-	1,563	994

Metallic Neutral Return is a neutral conductor for the 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 Case - 2007 Alternative Regulation Plan

On December 22, 2006, the VPSB approved a 9.09 percent rate increase for the Company, effective January 1, 2007. The rate increase allows us to recover increased power and transmission costs in 2007 compared to 2006. The VPSB also approved the Company's 2007 Alternative Regulation Plan, effective for three years beginning February 1, 2007. The 2007 Alternative Regulation Plan includes the following principal elements:

- A power supply cost adjustment mechanism under which the Company will recover or credit to customers, on a quarterly basis, 90 percent of power supply costs that are $300,000 (per quarter) higher or lower than power supply costs included in rates.
- An allowed rate of return on equity ("ROE") of 10.25 percent for 2007. The allowed ROE adjusts annually, up or down, in the amount of one-half the change in the ten-year Treasury bond rate.
- An annual earnings sharing mechanism under which the Company has the opportunity to earn up to 75 basis points above its allowed ROE and to recover earning shortfalls in excess of 100 basis points below the allowed ROE. Under the plan, certain exclusions, commonly made in setting rates, are applied to determine the Company's earnings and are expected to affect adversely the Company's ability to earn its allowed rate of return on equity for core utility operations.
- Base rates will be adjusted annually, based on the Company's cost of service. Non-power supply cost increases are capped at no more than $1.25 million in 2008 and $1.5 million in 2009, exclusive of ROE adjustments and extraordinary costs in excess of $600,000 per year. Base rate adjustments must be approved by the VPSB.
- The VPSB retains the authority to investigate the Company's rates at any time and to modify or terminate the plan.

The 2007 Alternative Regulation Plan creates opportunities and incentives for the Company to become more efficient, improve customer service, decouple earnings from increased electricity sales, streamline cost recovery, share efficiency savings with customers, increase credit quality, and reduce regulatory and borrowing costs borne by customers.

Retail Rate Case - 2003 Rate Plan

Under the 2003 Rate Plan, the Company began amortizing (recovering), in January 2005, certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

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

- 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;

- The Company and customers shall share equally any premium above book value realized by the Company's shareholders 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.

Accounting Order

During February 2006, the Company requested that the VPSB grant an accounting order to allow us to defer approximately $3.7 million in incremental hurricane-related power supply expenses to be incurred in the first quarter of 2006, and to also allow the Company to defer and amortize $1.3 million of incremental hurricane-related benefits realized in the fourth quarter of 2005 against these costs. The accounting order was approved by the VPSB in February 2006.

Other Legal Matters

The Company does not expect any litigation to result in a material adverse effect on its operating results or financial condition.

I. 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, 2006, the present value of the Company's obligation is approximately $3.5 million.

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

	For the Years ending December 31 (In thousands)
2007	$ 354
2008	354
2009	354
2010	354
2011	354
Total for 2012-2015	1,772
Total	$ 3,543

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.

J. 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 "Purchases from others" in the accompanying Consolidated Statements of Income.

Purchased power expense by significant contract supplier

	for the Yearsended December 31,		
	2006	**2005**	**2004**
In thousands			
Hydro Quebec	$ 55,045	$ 50,112	$ 48,309
Morgan Stanley	10,313	12,563	11,106
VYNPC	40,357	32,409	33,331
Small Power Producers	19,674	16,486	15,832
Stony Brook	1,947	1,667	1,696

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 2006 follows.

	Future Payments Contractually Due by Period				
At December 31, 2006	**Total**	**2007**	**2008 and 2009**	**2010 and 2011**	**After 2011**
			(In thousands)		
Hydro-Quebec power supply contracts	$ 475,117	$ 52,376	$ 103,582	$ 105,676	$ 213,483

JP Morgan contract	75,680	17,029	36,973	21,678	-
Independent Power Producers	120,610	17,145	31,332	29,619	42,514
Stony Brook contract	23,573	3,858	7,844	7,878	3,994
VYNPC PPA	189,308	33,744	73,155	72,118	10,292
Total	$ 884,288	$ 124,151	$ 252,886	$ 236,968	$ 270,283

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 between 100MW to 106MWof the plant output to the Company through 2012, adjusted for uprate, which is expected to represent 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	2006	$ 40,357
estimated	2007-2012	$ 36,318
Average cost per KWh	2006	$ 0.042
estimated	2007-2012	$ 0.043

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 maintains insurance for unscheduled outages for the Vermont Yankee plant and those costs are included in rates. The Company's outage insurance coverage is for 60 days and includes a $1 million deductible amount and is limited to $6 million total coverage for incremental on-peak energy replacement costs.

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 other 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 under the step-up provision would be approximately $692 million for the remainder of the contract, assuming that all other members of the VJO defaulted by January 1, 2007 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 had 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. During 2004, Hydro Quebec exercised its third and last option for deliveries occurring principally during 2005 that resulted in an incremental expense of $3.9 million based on current market prices. 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, exercised their last option to adjust deliveries by a five percent load factor in the fourth quarter of 2006 for delivery effective November 1, 2006 to October 31, 2007.

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, although 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 C3	
		(Dollars in thousands except per KWh)					
Capacity acquired			68 MW			46 MW	
Contract period			1995-2015			1995-2015	
Minimum energy purchase (annual load factor)			65%-75%			65%-75%	
Annual energy charge	2006	$	13,608		$	9,380	
estimated	2007-2015	$	14,514	(1)	$	10,015	(1)
Annual capacity charge	2006	$	16,774		$	11,504	
estimated	2007-2015	$	16,769	(1)	$	11,493	(1)
Average cost per KWh	2006	$	0.065		$	0.065	
estimated	2007-2015	$	0.072	(2)	$	0.072	(2)

(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 agreement 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 could 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 could purchase no more than 200,000 MWh in any given contract year ending October 31. As of December 31, 2005, Hydro Quebec had purchased all MWh available under option B.

Hydro Quebec exercised options A and B for 2004 and 2005, and the Company purchased replacement power at a net cost of $3.2 million and $2.7 million, respectively. The Company has also covered option A during 2006 at a net cost of $7.4 million. The Company received an accounting order from the VPSB to defer $2.1 million of the 2006 expense. Hydro Quebec’s call for 2006 was made during the fourth quarter of 2005 for delivery during January and February, timed to take advantage of extremely high forward energy prices resulting from the effects of hurricanes Katrina and Wilma that interrupted gas production in the Gulf of Mexico. Energy prices in the northeast are heavily dependent upon natural gas prices.

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 supplied approximately 15 percent of the Company's estimated customer demand ("load").

Under the Morgan Stanley Contract which expired on December 31, 2006, on a daily basis, and at Morgan Stanley’s discretion, we sold power to Morgan Stanley from part of our portfolio of power resources at predefined operating and pricing parameters. Morgan Stanley sold to the Company, at a predefined price, power sufficient to serve pre-established load requirements.

The Company purchased the following amounts from Morgan Stanley for the years indicated:

		The Morgan Stanley Contract
Capacity acquired*		1-182 MW
Contract period expired		2006
Annual energy charge :		
2004	$	11.1 million
2005	$	12.6 million
2006	$	10.3 million

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

The JP Morgan Contract

The Company entered into a contract with JP Morgan Ventures Energy Corporation (the "JP Morgan Contract") during 2006 to purchase approximately 10 percent of the Company's retail load requirements for a four year period commencing January 1, 2007 and ending December 31, 2010. The contract is for firm physical delivery of specified hourly quantities and is not associated with any generation source and not subject to outage risk. There is no optionality under the contract for either party. Estimated purchases under the JP Morgan Contract are approximately $17 million for 2007, $21 million for 2008, $16 million for 2009, and $22 million for 2010.

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 "Purchases from others" 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 2006 follows:

		Stony Brook
		(Dollars in thousands)
Plant capacity		352.0 MW
Company's share of output		4.40%
Company's annual share of:		
Interest	$	75
Other debt service		493
Other capacity		511
Total annual capacity	$	1,079
Company's share of long-term debt	$	759

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 2006, the Company received 151,382 MWh under these long-term contracts at a cost of $19.7 million. These IPP purchases amount to 6.7 percent of the Company's total MWh purchased and 14.7 percent of purchase power expenses. Estimated purchases from IPPs are expected to range between approximately $14.9 million and $17.1 million for the years 2007 through 2011.

K. 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		**2006 Quarter ended**			
	March	**June**	**September**	**December**	**Total**
Operating revenues	$ 60,976	$ 59,380	$ 61,433	$ 58,687	$ 240,476
Operating income	4,958	3,366	4,052	3,745	16,121

Net income-continuing operations		3,536		2,026		2,831		1,538		9,931
Net income-discontinued operations		76		-		53		63		192
Net Income applicable to common stock	$	3,612	$	2,026	$	2,884	$	1,601	$	10,123
Basic earnings per share from:										
Continuing operations	$	0.68	$	0.39	$	0.54	$	0.28	$	1.88
Discontinued operations		0.01		-		0.01		0.02		0.04
Basic earnings per share	$	0.69	$	0.39	$	0.55	$	0.29	$	1.92
Weighted average common shares outstanding		5,243		5,260		5,280		5,296		5,270
Diluted earnings per share from:										
Continuing operations	$	0.67	$	0.38	$	0.53	$	0.26	$	1.85
Discontinued operations		0.01		-		0.01		0.02		0.04
Diluted earnings per share	$	0.68	$	0.38	$	0.54	$	0.28	$	1.89
Weighted average common and common equivalent shares outstanding		5,319		5,323		5,362		5,388		5,348

Amounts in thousands except per share data				**2005 Quarter ended**						
		March		**June**		**September**		**December**		**Total**
Operating revenues	$	58,248	$	54,888	$	57,584	$	75,140	$	245,860
Operating income		4,326		3,647		3,839		4,269		16,081
Net income-continuing operations		2,981		2,384		2,524		3,157		11,046
Net income-discontinued operations		(2)		(3)		18		121		134
Net Income applicable to common stock	$	2,979	$	2,381	$	2,542	$	3,278	$	11,180
Basic earnings per share from:										
Continuing operations	$	0.58	$	0.46	$	0.49	$	0.58	$	2.12
Discontinued operations		-		-		-		0.03		0.03
Basic earnings per share	$	0.58	$	0.46	$	0.49	$	0.61	$	2.15
Weighted average common shares outstanding		5,160		5,186		5,208		5,224		5,195
Diluted earnings per share from:										
Continuing operations	$	0.56	$	0.45	$	0.48	$	0.60	$	2.09
Discontinued operations		-		-		-		0.03		0.03
Diluted earnings per share	$	0.56	$	0.45	$	0.48	$	0.63	$	2.12
Weighted average common and common equivalent shares outstanding		5,301		5,271		5,301		5,318		5,284

				2004 Quarter ended						
		March		**June**		**September**		**December**		**Total**
Operating revenues	$	63,123	$	54,585	$	54,926	$	56,182	$	228,816
Operating income		5,019		2,776		4,595		3,088		15,478
Net income-continuing operations		3,740		1,783		3,392		2,144		11,059
		(6)		(1)		(2)		534		525

Net income-discontinued operations										
Net Income applicable to common stock	$	3,734	$	1,782	$	3,390	$	2,678	$	11,584
Basic earnings per share from:										
Continuing operations	$	0.74	$	0.35	$	0.67	$	0.42	$	2.18
Discontinued operations		-		-		-		0.10		0.10
Basic earnings per share	$	0.74	$	0.35	$	0.67	$	0.52	$	2.28
Weighted average common shares outstanding		5,046		5,072		5,089		5,124		5,083
Diluted earnings per share from:										
Continuing operations	$	0.72	$	0.34	$	0.65	$	0.39	$	2.10
Discontinued operations		-		-		-		0.10		0.10
Diluted earnings per share	$	0.72	$	0.34	$	0.65	$	0.49	$	2.20
Weighted average common and common equivalent shares outstanding		5,205		5,228		5,251		5,282		5,254

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, 2006 and 2005, and the related consolidated statements of income, changes in stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, in 2006, the Company adopted the provisions of Statement of Financial Accounting Standard No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*.

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, 2006, 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 12, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 12, 2007

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, as amended, 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 amended) 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 are effective.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, 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 implemented by the company’s management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Management’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 Company’s assets; (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; 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.

In connection with the preparation of the Company’s annual financial statements, our management has undertaken an assessment, which includes the design and operational effectiveness of our internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as “COSO”. The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that its internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of the Company’s financial reporting and the preparation of its financial statements as of December 31, 2006 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2006.

The Company's external auditors, Deloitte & Touche LLP, have audited our financial statements for the year ended December 31, 2006 included in this annual report on Form 10-K and, as part of that audit, have issued a report on management's assessment of internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

Changes in Internal Controls

We continue to review, revise and improve the effectiveness of our internal control over financial reporting. We have made no change in our internal control over financial reporting in connection with our fourth quarter evaluation that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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") maintained effective internal control over financial reporting as of December 31, 2006, 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.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006, of the Company and our report dated March 12, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding Green Mountain Power Corporation’s accounting changes resulting from the adoption of a new accounting standard.

DELOITTE & TOUCHE LLP
Boston, Massachusetts
March 12, 2007

ITEM 9B. OTHER INFORMATION

Pursuant to Item 1.01 of Current Report on Form 8-K, the Company provides the disclosures included in Exhibits 10.d.76 and 10.d.77 hereto.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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. Such information is incorporated herein by reference.

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 20, 2006. 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," "Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," "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. Such information is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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.

Date: March 12, 2007	GREEN MOUNTAIN POWER CORPORATION 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 (principal executive officer)	March 12, 2007
/s/Mary G. Powell Mary G. Powell	Chief Operating Officer, Senior Vice President	March 12, 2007
/s/Dawn D. Bugbee Dawn D. Bugbee	Chief Financial Officer, Vice President and Treasurer (principal financial officer and principal accounting officer)	March 12, 2007
*Nordahl L. Brue)	Chairman of the Board	
*Elizabeth A. Bankowski)		
*William H. Bruett)		
*Merrill O. Burns)		
*David R. Coates)	Directors	
*Kathleen C. Hoyt)		
*Euclid A. Irving)		
*Marc A. vanderHyeyden)		
*By: /s/Christopher L. Dutton Christopher L. Dutton (Attorney - in - Fact)		March 12, 2007

ITEM 15(a) 3 and Item 15c. Exhibits

Exhibit Number	Description	Exhibit	SEC Docket Incorporated By reference Or Page filed herewith
3.1	Amended and Restated Articles of Incorporation dated May 27, 2004	3A	Form 10-Q June 2004
3.c	By-laws of the Company, as amended December 8, 2003	3	Form 8-K Dec. 8 2003 (1-8291)
4.b.1	Indentures of First Mortgage and Deed of Trust dated as of February 1, 1955	4.b	2-27300
4.b.2	First Supplemental Indentures dated as of April 1, 1961	4.b.2	2-75293
4.b.3	Second Supplement Indenture dated as of January 1, 1966	4.b.3	2-75293
4.b.4	Third Supplemental Indenture dated as of July 1, 1968	4.b.4	2-75293
4.b.5	Fourth Supplemental Indenture dated as of October 1, 1969	5.b.5	2-75293
4.b.6	Fifth Supplemental Indenture dated as of December 1, 1973	4.b.6	2-75293
4.b.7	Seventh Supplemental Indenture dated as of August 1, 1976	4.b.7	2-99643
4.b.8	Eighth Supplement Indentures dated as of December 1, 1979	4.b.8	2-99643
4.b.9	Ninth Supplemental Indenture dated as of July 15, 1985	4.b.9	2-99643
4.b.10	Tenth Supplemental Indenture dated as of June 15, 1989	4.b.10	Form 10-K 1989 (1-8291)
4.b.11	Eleventh Supplemental Indenture dated as of September 1, 1990	4.b.11	Form 10-Q Sept. 1990 (1-8291)
4.b.12	Twelfth Supplemental Indenture dated as of March 1, 1992	4.b.12	Form 10-K 1991 (1-8291)
4.b.13	Thirteenth Supplemental Indenture dated as of March 1, 1992	4.b.13	Form 10-K 1991 (1-8291)
4.b.14	Fourteenth Supplemental Indenture dated as of November 1, 1993	4.b.14	Form 10-K 1993 (1-8291)
4.b.15	Fifteenth Supplemental Indenture dated as of November 1, 1993	4.b.15	Form 10-K 1993 (1-8291)
4.b.16	Sixteenth Supplemental Indenture dated as of December 1, 1995	4.b.16	Form 10-K 1995 (1-8291)
4.b.17	Revised form of Indenture as filed as an Exhibit to Registration Statement No. 33-59383	4.b.17	Form 10-Q Sept. 1995 (1-8291)
4.b.18	Credit Agreement by and among Green Mountain Power, The Bank of Nova Scotia, State Street Bank and Trust Company, Fleet National Bank, and Fleet National Bank, as Agent	4.b.18	Form 10-K 1997 (1-8291)
4.b.18(a)	Amendment to Exhibit 4.b.18	4.b.18(a)	Form 10-Q Sept. 1998 (1-8291)
4.b.19	Seventeenth Supplemental Indenture dated as of December 1, 2002	4.b.19	Form 10-K 2002 (1-8291)
4.b.20		4.b.20	Form 8-K

	Revolving Credit Agreement with Sovereign Bank, Keybank National Association and Sovereign Bank, as Agent		June 19, 2006
4.b.21	Eighteenth Supplemental Indenture dated as of July 1, 2006	4.b.21	Form 8-K August 3, 2006
4.b.22	Bond Purchase Agreement dated as of July 27, 2006 between Green Mountain Power Corporation and CIGNA Investments, Inc. and Hartford Life Insurance Company, as purchasers.	4.b.22	Form 8-K August 3, 2006
10.a	Form of Insurance Policy issued by Pacific Insurance Company, with respect to indemnification of Directors and Officers.	10.a	33-8146
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	2-27300
10.b.2	Power Contract, dated February 1, 1968, between the Company and Vermont Yankee Nuclear Power Corporation	13.d	2-34346
10.b.3	Amendment, dated June 1, 1972, to Power Contract between the Company and Vermont Yankee Nuclear Power Corporation	13.f.1	2-49697
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)	33-8164
10.b.3(b)	Additional Power Contract, dated February 1, 1984, between the Company and Vermont Yankee Nuclear Power Corporation	10.b.3(b)	33-8164
10.b.4	Capital Funds Agreement, dated February 1, 1968, between the Company and Vermont Yankee Nuclear Power Corporation	13.e	2-34346
10.b.5	Amendment, dated March 12, 1968, to Capital Funds Agreement between the Company and Vermont Yankee Nuclear Power Corporation	13.f	2-34346
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	2-75293
10.b.7	Three-Party Power Agreement among the Company, VELCO and Central Vermont Public Service Corporation dated November 19, 1969	13.i	2-49697
10.b.8	Amendment to Exhibit 10.b.7, dated June 1, 1981	10.b.8	2-75293

Exhibit Number	Description	Exhibit	SEC Docket Incorporated By reference Or Page filed Herewith
10.b.9	Three-Party Transmission Agreement among the Company, VELCO and Central Vermont Public Service Corporation, dated November 21, 1969	10.b.9	2-49697
10.b.10	Amendment to Exhibit 10.b.9, dated June 1, 1981	10.b.10	2-75293
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	2-52900
10.b.15	New England Power Pool Agreement as amended to November 1, 1975	4.8	2-55385
10.b.16	Bulk Power Transmission Contract between the Company and VELCO dated June 1, 1968	13.v	2-49697
10.b.17	Amendment to Exhibit 10.b.16, dated June 1, 1970	13.v.i	2-49697
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	33-8164
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	33-8164
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	33-8164
10.b.30	Bulk Power Purchase Contract dated April 7, 1976, between VELCO and the Company	10.b.32	2-75293
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	33-8164
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	33-8164
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	33-8164
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	33-8164

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 transmission interconnection between New England and Hydro Quebec.	10.b.39	33-8164
10.d.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	33-8164
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	33-8164
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	33-8164
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	33-8164
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	33-8164
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	33-8164

Exhibit Number	Description	Exhibit	SEC Docket Incorporated By reference Or Page filed Herewith
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	33-8164
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	33-8164
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	33-8164
10.b.61	Agreements entered in connection with Phase II of the NEPOOL/Hydro Quebec + 450 KV HVDC Transmission Interconnection	10.b.61	33-8164
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	33-8164
10.b.68	Firm Power and Energy Contract dated December 4, 1987, between Hydro Quebec and participating Vermont utilities, including the Company, for the purchase of firm power for up to thirty years	10.b.68	Form 10-K 1992 (1-8291)
10.b.69	Firm Power Agreement dated as of October 26, 1987, between Ontario Hydro and Vermont Department of Public Service	10.b.69	Form 10-K 1992 (1-8291)
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 10-K 1992 (1-8291)
10.b.70(a)	Amendment to 10.b.70	10.b.70(a)	Form 10-K 1992 (1-8291)
10.b.71	Interconnection Agreement dated as of February 23, 1987, between the Vermont Joint Owners of the Highgate facilities and Hydro Quebec	10.b.71	Form 10-K 1992 (1-8291)
10.b.72	Participation Agreement dated as of April 1, 1988, between Hydro Quebec and participating Vermont utilities, including the Company, implementing the purchase of firm power for up to 30 years under the Firm Power and Energy Contract dated December 4, 1987 (previously filed with the Company's Annual Report on Form 10-K for 1987, Exhibit Number 10.b.68	10.b.72	Form 10-Q June 1988 (1-8291)
10.b.72(a)	Restatement of the Participation Agreement filed as Exhibit 10.b.72 on Form 10-Q for June 1988	10.b.72(a)	Form 10-K 1988 (1-8291)
10.b.77	Firm Power and Energy Contract dated December 29, 1988 between Hydro Quebec and participating Vermont utilities, including the Company, for the purchase of up to 54 MW of firm power and energy	10.b.77	Form 10-K 1988 (1-8291)

10.b.78	Transmission Agreement dated December 23, 1988, between the Company and Niagara Mohawk Power Corporation (Niagara Mohawk), for Niagara Mohawk to provide electric transmission to the Company from Rochester Gas and Electric and Central Hudson Gas and Electric	10.b.78	Form 10-K 1988 (1-8291)
10.b.81	Sales Agreement dated May 24, 1989, between the Town of Hardwick, Hardwick Electric Department and the Company for the Company to purchase all of the output of Hardwick's generation and transmission sources and to provide Hardwick with all-requirements energy and capacity except for that provided by the Vermont Department of Public Service or Federal Preference Power	10.b.81	Form 10-Q June 1989 (1-8291)
10.b.82	Sales Agreement dated July 14, 1989, between Northfield Electric Department and the Company for the Company to purchase all of the output of Northfield's generation and transmission sources and to provide Northfield with all-requirements energy and capacity except for that provided by the Vermont Department of Public Service or Federal Preference Power	10.b.82	Form 10-Q June 1989 (1-8291)
10.b.85	Power Purchase and Sale Agreement between Morgan Stanley Capital Group Inc. and the Company.	10.b.85	Form 10-K 1998 (1-8291)
10.b.90	Power Purchase Agreement between Entergy Nuclear Vermont Yankee LLC and Vermont Yankee Nuclear Power Corporation	10.b.90	Form 10-Q June 2002 (1-8291)
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 10-Q June 2002 (1-8291)
10.b.92	Amendment to Power Purchase and Sale Agreement between Morgan Stanley Capital Group, Inc. and the Company	10.b.92	Form 10-K 2002 (1-8291)
10.b.93	2001 Amendatory Agreement - Power Supply Agreement between the Company and Vermont Yankee Nuclear Power Corporation	10.b.93	Form 10-K 2004
10.b.94	Agreement and Plan of Merger by and among Northern New England Energy Corporation, Northstars Merger Subsidiary Corporation and Green Mountain Power Corporation, dated as of June 21, 2006	10.b.94	Form 8-K June 22, 2006
10.b.95	Amended and Restated Three-Party Transmission Agreement between Vermont Electric Power Company, Inc., Central Vermont Public Service Corporation, Green Mountain Power Corporation, and Vermont Transco LLC.	10.b.95	Form 10-Q June 2006
10.b.96	Amended and Restated Three-Party Agreement between Vermont Electric Power Company, Inc., Central Vermont Public Service Corporation, Green Mountain Power Corporation, and Vermont Transco LLC.	10.b.96	Form 10-Q June 2006

	Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K to Item 14(c)., all under SEC Docket 1-8291		
10.d.1b	Green Mountain Power Corporation Second Amended and Restated Deferred Compensation Plan for Directors	10.d.1b	Form 10-K 1993
10.d.1c	Green Mountain Power Corporation Second Amended and Restated Deferred Compensation Plan for Officers	10.d.1c	Form 10-K 1993
10.d.1d	Amendment No. 93.1 to the Amended and Restated Deferred Compensation Plan for Officers	10.d.1d	Form 10-K 1993
10.d.1e	Amendment No. 94.1 to the Amended and Restated Deferred Compensation Plan for Officers	10.d.1e	Form 10-Q June 1994
10.d.2	Green Mountain Power Corporation Medical Expense Reimbursement Plan	10.d.2	Form 10-K 1991
10.d.4	Green Mountain Power Corporation Officers’ Insurance Plan	10.d.4	Form 10-K 1991
10.d.4a	Green Mountain Power Corporation Officers' Insurance Plan as amended	10.d.4a	Form 10-K 1990
10.d.8	Green Mountain Power Corporation Officers' Supplemental Retirement Plan	10.d.8	Form 10-K 1990
10.d.15c	Green Mountain Power 2000 Stock Incentive Plan	10.d.15c	Form 10-K 2001
10.d.40	Change in Control Agreement with C. L. Dutton	10.d.40	Form 10-K 2003
10.d.41	Change in Control Agreement with D. J. Rendall, Jr.	10.d.41	Form 10-K 2003
10.d.42	Change in Control Agreement with R. J. Griffin	10.d.42	Form 10-K 2003
10.d.43	Change in Control Agreement with W. S. Oakes	10.d.43	Form 10-K 2003
10.d.44	Change in Control Agreement with M. G. Powell	10.d.44	Form 10-K 2003
10.d.45	Change in Control Agreement with R. E. Rogan	10.d.45	Form 10-K 2005
10.d.46	Deferred Stock Unit Agreement with D. J. Rendall, Jr.	10.d.46	Form 10-K 2003
10.d.47	Deferred Stock Unit Agreement with C. L. Dutton	10.d.47	Form 10-K 2003
10.d.48	Deferred Stock Unit Agreement with S. C. Terry	10.d.48	Form 10-K 2003
10.d.49	Deferred Stock Unit Agreement with R. J. Griffin	10.d.49	Form 10-K 2003
10.d.50	Deferred Stock Unit Agreement with W. S. Oakes	10.d.50	Form 10-K 2003
10.d.51	Deferred Stock Unit Agreement with M. G. Powell	10.d.51	Form 10-K 2003
10.d.52	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.52	Form 10-K 2003
10.d.53	Deferred Stock Unit Agreement with N. L. Brue	10.d.53	Form 10-K 2003
10.d.54	Deferred Stock Unit Agreement with W. H. Bruett	10.d.54	

			Form 10-K 2003
10.d.55	Deferred Stock Unit Agreement with M. O. Burns	10.d.55	Form 10-K 2003
10.d.56	Deferred Stock Unit Agreement with D. R. Coates	10.d.56	Form 10-K 2003
10.d.57	Deferred Stock Unit Agreement with E. A. Irving	10.d.57	Form 10-K 2003
10.d.58	Director Deferral Agreement with E. A. Bankowski	10.d.58	Form 10-K 2003
10.d.59	Director Deferral Agreement with M. O. Burns	10.d.59	Form 10-K 2003
10.d.60	Director Deferral Agreement with D. R. Coates	10.d.60	Form 10-K 2003
10.d.61	Director Deferral Agreement with E. A. Irving	10.d.61	Form 10-K 2003
10.d.62	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.62	Form 10-Q June 2004
10.d.63	Deferred Stock Unit Agreement with N. L. Brue	10.d.63	Form 10-Q June 2004
10.d.64	Deferred Stock Unit Agreement with W. H. Bruett	10.d.64	Form 10-Q June 2004
10.d.65	Deferred Stock Unit Agreement with M. O. Burns	10.d.65	Form 10-Q June 2004
10.d.66	Deferred Stock Unit Agreement with D. R. Coates	10.d.66	Form 10-Q June 2004
10.d.67	Deferred Stock Unit Agreement with K. C. Hoyt	10.d.67	Form 10-Q June 2004
10.d.68	Deferred Stock Unit Agreement with E. A. Irving	10.d.68	Form 10-Q June 2004
10.d.69	Deferred Stock Unit Agreement with M. A. vanderHeyden	10.d.69	Form 10-Q June 2004
10.d.70	Director Deferral Agreement with E. A. Bankowski	10.d.70	Form 8-K Dec. 2, 2004
10.d.71	Director Deferral Agreement with M. O. Burns	10.d.71	Form 8-K Dec. 2, 2004
10.d.72	Director Deferral Agreement with E. A. Irving	10.d.72	Form 8-K Dec. 2, 2004
10.d.73	Officer Deferral Agreement with S. C. Terry	10.d.73	Form 8-K Dec. 2, 2004
10.d.74	Officer Deferral Agreement with W. S. Oakes	10.d.74	Form 8-K Dec. 2, 2004
10.d.75	Board of Directors' Resolutions Amending Deferred Compensation Plan	10.d.75	Form 8-K Dec. 30, 2004
10.d.76	Officer Compensation Table	10.d.76	Form 10-K 2006
10.d.77	2006 Management Compensation Plan Description	10.d.77	Form 10-K 2006

	Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K to Item 14(c)., all under SEC Docket 1-8291		
10.d.1b	Green Mountain Power Corporation Second Amended and Restated Deferred Compensation Plan for Directors	10.d.1b	Form 10-K 1993
10.d.1c	Green Mountain Power Corporation Second Amended and Restated Deferred Compensation Plan for Officers	10.d.1c	Form 10-K 1993
10.d.1d	Amendment No. 93.1 to the Amended and Restated Deferred Compensation Plan for Officers	10.d.1d	Form 10-K 1993
10.d.1e	Amendment No. 94.1 to the Amended and Restated Deferred Compensation Plan for Officers	10.d.1e	Form 10-Q June 1994
10.d.2	Green Mountain Power Corporation Medical Expense Reimbursement Plan	10.d.2	Form 10-K 1991
10.d.4	Green Mountain Power Corporation Officers’ Insurance Plan	10.d.4	Form 10-K 1991
10.d.4a	Green Mountain Power Corporation Officers' Insurance Plan as amended	10.d.4a	Form 10-K 1990
10.d.8	Green Mountain Power Corporation Officers' Supplemental Retirement Plan	10.d.8	Form 10-K 1990
10.d.15c	Green Mountain Power 2000 Stock Incentive Plan	10.d.15c	Form 10-K 2001
10.d.40	Change in Control Agreement with C. L. Dutton	10.d.40	Form 10-K 2003
10.d.41	Change in Control Agreement with D. J. Rendall, Jr.	10.d.41	Form 10-K 2003
10.d.42	Change in Control Agreement with R. J. Griffin	10.d.42	Form 10-K 2003
10.d.43	Change in Control Agreement with W. S. Oakes	10.d.43	Form 10-K 2003
10.d.44	Change in Control Agreement with M. G. Powell	10.d.44	Form 10-K 2003
10.d.45	Change in Control Agreement with R. E. Rogan	10.d.45	Form 10-K 2005
10.d.46	Deferred Stock Unit Agreement with D. J. Rendall, Jr.	10.d.46	Form 10-K 2003
10.d.47	Deferred Stock Unit Agreement with C. L. Dutton	10.d.47	Form 10-K 2003
10.d.48	Deferred Stock Unit Agreement with S. C. Terry	10.d.48	Form 10-K 2003
10.d.49	Deferred Stock Unit Agreement with R. J. Griffin	10.d.49	Form 10-K 2003
10.d.50	Deferred Stock Unit Agreement with W. S. Oakes	10.d.50	Form 10-K 2003
10.d.51	Deferred Stock Unit Agreement with M. G. Powell	10.d.51	Form 10-K 2003
10.d.52	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.52	Form 10-K 2003
10.d.53	Deferred Stock Unit Agreement with N. L. Brue	10.d.53	Form 10-K 2003
10.d.54	Deferred Stock Unit Agreement with W. H. Bruett	10.d.54	

			Form 10-K 2003
10.d.55	Deferred Stock Unit Agreement with M. O. Burns	10.d.55	Form 10-K 2003
10.d.56	Deferred Stock Unit Agreement with D. R. Coates	10.d.56	Form 10-K 2003
10.d.57	Deferred Stock Unit Agreement with E. A. Irving	10.d.57	Form 10-K 2003
10.d.58	Director Deferral Agreement with E. A. Bankowski	10.d.58	Form 10-K 2003
10.d.59	Director Deferral Agreement with M. O. Burns	10.d.59	Form 10-K 2003
10.d.60	Director Deferral Agreement with D. R. Coates	10.d.60	Form 10-K 2003
10.d.61	Director Deferral Agreement with E. A. Irving	10.d.61	Form 10-K 2003
10.d.62	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.62	Form 10-Q June 2004
10.d.63	Deferred Stock Unit Agreement with N. L. Brue	10.d.63	Form 10-Q June 2004
10.d.64	Deferred Stock Unit Agreement with W. H. Bruett	10.d.64	Form 10-Q June 2004
10.d.65	Deferred Stock Unit Agreement with M. O. Burns	10.d.65	Form 10-Q June 2004
10.d.66	Deferred Stock Unit Agreement with D. R. Coates	10.d.66	Form 10-Q June 2004
10.d.67	Deferred Stock Unit Agreement with K. C. Hoyt	10.d.67	Form 10-Q June 2004
10.d.68	Deferred Stock Unit Agreement with E. A. Irving	10.d.68	Form 10-Q June 2004
10.d.69	Deferred Stock Unit Agreement with M. A. vanderHeyden	10.d.69	Form 10-Q June 2004
10.d.70	Director Deferral Agreement with E. A. Bankowski	10.d.70	Form 8-K Dec. 2, 2004
10.d.71	Director Deferral Agreement with M. O. Burns	10.d.71	Form 8-K Dec. 2, 2004
10.d.72	Director Deferral Agreement with E. A. Irving	10.d.72	Form 8-K Dec. 2, 2004
10.d.73	Officer Deferral Agreement with S. C. Terry	10.d.73	Form 8-K Dec. 2, 2004
10.d.74	Officer Deferral Agreement with W. S. Oakes	10.d.74	Form 8-K Dec. 2, 2004
10.d.75	Board of Directors' Resolutions Amending Deferred Compensation Plan	10.d.75	Form 8-K Dec. 30, 2004
10.d.76	Officer Compensation Table	10.d.76	Form 10-K 2006
10.d.77	2006 Management Compensation Plan Description	10.d.77	Form 10-K 2006

	Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K to Item 14(c)., all under SEC Docket 1-8291		
10.d.79	Green Mountain Power Corporations New Supplemental Retirement Plan with C. L. Dutton	10.d.79	Form 8-K 2005 July 29, 2005
10.d.80	Green Mountain Power Corporations New Supplemental Retirement Plan with R. J. Griffin	10.d.80	Form 8-K 2005 July 29, 2005
10.d.81	Green Mountain Power Corporations New Supplemental Retirement Plan with W. S. Oakes	10.d.81	Form 8-K 2005 July 29, 2005
10.d.82	Green Mountain Power Corporations New Supplemental Retirement Plan with M. G. Powell	10.d.82	Form 8-K 2005 July 29, 2005
10.d.83	Green Mountain Power Corporations New Supplemental Retirement Plan with D. J. Rendall, Jr.	10.d.83	Form 8-K 2005 July 29, 2005
10.d.84	Green Mountain Power Corporations Officers' Supplemental Retirement Plan with S. C. Terry	10.d.84	Form 10-K 2004
10.d.86	Green Mountain Power Corporation 2004 Stock Incentive Plan	10.d.86	Form 10-K 2005
10.d.87	Green Mountain Power Corporation Third Amended and Restated Deferred Compensation Plan for Certain Officers	10.d.87	Form 10-K 2004
10.d.88	2005 Officer Deferred Stock Unit Agreement with Christopher L. Dutton	10.d.88	Form 8-K May 27, 2005
10.d.89	2005 Officer Deferred Stock Unit Agreement with Robert J. Griffin	10.d.89	Form 8-K May 27, 2005
10.d.90	2005 Officer Deferred Stock Unit Agreement with Walter S. Oakes	10.d.90	Form 8-K May 27, 2005
10.d.91	2005 Officer Deferred Stock Unit Agreement with Mary G. Powell	10.d.91	Form 8-K May 27, 2005
10.d.92	2005 Officer Deferred Stock Unit Agreement with Donald J. Rendall, Jr.	10.d.92	Form 8-K May 27, 2005
10.d.93	2005 Officer Deferred Stock Unit Agreement with Stephen C. Terry	10.d.93	Form 8-K May 27, 2005
10.d.94	Officer Deferred Stock Unit Agreement with Stephen C. Terry	10.d.94	Form 8-K May 27, 2005
10.d.95	2005 Supplemental Retirement Plan with Stephen C. Terry	10.d.95	Form 8-K May 27, 2005
10.d.96	2005 Director Deferred Stock Unit Agreement with Elizabeth A. Bankowski	10.d.96	Form 8-K July 26, 2005
10.d.97	2005 Director Deferred Stock Unit Agreement with Nordahl L. Brue	10.d.97	Form 8-K July 26, 2005
10.d.98	2005 Director Deferred Stock Unit Agreement with William H. Bruett	10.d.98	Form 8-K July 26, 2005
10.d.99	2005 Director Deferred Stock Unit Agreement with Merrill O. Burns	10.d.99	Form 8-K July 26, 2005
10.d.100	2005 Director Deferred Stock Unit Agreement with David R. Coates	10.d.100	Form 8-K July 26, 2005
10.d.101	2005 Director Deferred Stock Unit Agreement with Kathleen C. Hoyt	10.d.101	Form 8-K July 26, 2005
10.d.102	2005 Director Deferred Stock Unit Agreement with Euclid A. Irving	10.d.102	Form 8-K July 26, 2005
10.d.103		10.d.103	Form 8-K

	2005 Director Deferred Stock Unit Agreement with Marc A. vanderHeyden		July 26, 2005
10.d.104	Director Deferral Agreement with David R. Coates	10.d.104	Form 8-K January 4, 2006
10.d.105	Change in Control Agreement with D. D. Bugbee	10.d.105	Form 8-K March 7, 2006
10.d.106	Green Mountain Power Corporations Supplemental Retirement Plan with D. D. Bugbee	10.d.106	Form 8-K March 7, 2006
10.d.107	Amendment to Change in Control Agreement with R. J. Griffin	10.d.107	Form 8-K March 7, 2006
10.d.108	Form of 2006 Officer Deferred Stock Unit Agreement with C. L. Dutton, D. D. Bugbee, R. J. Griffin, W. S. Oakes, M. G. Powell, D. J. Rendall, Jr., and R. E. Rogan	10.d.108	Form 8-K May 23, 2006
10.d.109	Rights Agreement, dated June 17, 1998, between Green Mountain Power Corporation and Mellon Investor Services, LLC (f/k/a ChaseMellon Shareholders Services, L.L.C.)(incorporated by reference from Exhibit 4.a.1 from the Company's Current Report on Form 8-K filed on June 19, 1998)	10.d.109	Form 8-K June 22, 2006
10.d.110	Amendment to Rights Agreement, Dated June 21, 2006, between Green Mountain Power Corporation and Mellon Investor Services LLC (f/k/a ChaseMellon Shareholder Services, L.L.C.)	10.d.110	Form 8-K June 22, 2006
10.d.111	Resolutions of the Compensation Committee of the Board of Directors of the Company adopted on June 21, 2006, approving certain actions under the 2000 and 2004 Stock Incentive Plans	10.d.111	Form 8-K June 22, 2006
10.d.112	Form of consent provided by the Company's executive officers and directors in connection with Awards issued under the 2000 and 2004 Stock Incentive Plans	10.d.112	Form 8-K June 22, 2006
10.d.113	Resolutions of the Compensation Committee of the Board of Directors of the Company adopted on June 21, 2006, amending certain executive Supplemental Retirement Plans	10.d.113	Form 8-K June 22, 2006

	Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K to Item 14(c)., all under SEC Docket 1-8291		
10.d.114	Form of consent provided by the Company's executive officers in connection with the Amendments to the Supplemental Retirement Plans	10.d.114	Form 8-K June 22, 2006
10.d.115	Form of 2006 Director Deferred Stock Unit Agreement	10.d.115	Form 8-K July 25, 2006
10.d.116	Resolutions of the Compensation Committee of the Board of Directors of the Company adopted on October 30, 2006, approving certain actions under the Company's 2004 Stock Incentive Plan	10.d.116	Form 8-K November 1, 2006
10.d.117	Form of consent provided by the Company's executive officers and directors in connection with DSUs issued under the Company's 2004 Stock Incentive Plan	10.d.117	Form 8-K November 1, 2006
10.d.118	Resolutions of the Board of Directors of Green Mountain Power Corporation adopted on December 4, 2006 amending (effective as of January 1, 2007) the Company's Deferred Compensation Plan for Certain Officers	10.d.118	Form 8-K December 7, 2006
14	Green Mountain Power Corporation's Code of Ethics and Conduct dated October 6, 2003	14	Form 10-K 2004
23.1	Consent of Deloitte and Touche LLP	23.1	
24	Limited Power of Attorney	24	
31.1	Certification of Christopher L. Dutton, President and Chief Executive Officer, pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Act of 1934, as Adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.1	Form 10-K 2006
31.2	Certification of Dawn D. Bugbee, Chief Financial Officer, Vice President and Treasurer pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Act of 1934, as Adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.2	Form 10-K 2006
32.1	Certification of Christopher L. Dutton, President and Chief Executive Officer, Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1	Form 10-K 2006
32.2	Certification of Dawn D. Bugbee, Chief Financial Officer, Vice President and Treasurer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.2	Form 10-K 2006