GREEN MOUNTAIN POWER CORP
Form 10-Q
May 09, 2006

United States
Securities and Exchange Commission
Washington, D.C. 20549

FORM 10-Q

x Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended March 31, 2006

or

o 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 1-8291

GREEN MOUNTAIN POWER CORPORATION

(Exact name of registrant as specified in its charter)

Vermont (State or other jurisdiction of incorporation or organization	**03-0127430** (I.R.S. Employer Identification No.)
163 Acorn Lane **Colchester, Vermont** (Address of Principal Executive Offices)	**05446** (Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filed. See definition of "accelerated filer and large accelerated filed" in Rule 12b-2 of the Exchange Act. (Check One) Large Accelerated Filer o Accelerated Filer x Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

The number of shares of Common Stock, $3.33 1/3 par value, outstanding as of April 28, 2006: 5,253,958.

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 including 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.

AVAILABLE INFORMATION

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

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

GREEN MOUNTAIN POWER CORPORATION
Consolidated Comparative Income Statements

	Unaudited Three Months Ended March 31	
In thousands, except per share data	**2006**	**2005**
Operating revenues		
Retail Revenues	$ 53,950	$ 54,420
Wholesale Revenues	7,026	3,828
Total operating revenues	60,976	58,248
Operating expenses		
Power Supply		
Vermont Yankee Nuclear Power Corporation	9,092	8,695
Company-owned generation	1,344	1,540
Purchases from others	25,000	25,115
Other operating	5,457	4,882
Transmission	4,931	4,172
Maintenance	2,815	2,345
Depreciation and amortization	3,637	3,776
Taxes other than income	1,711	1,722
Income taxes	2,031	1,675
Total operating expenses	56,018	53,922
Operating income	4,958	4,326
Other income		
Equity in earnings of affiliates and non-utility operations	410	397
Allowance for equity funds used during construction	11	7
Other income (deductions), net	(52)	(54)
Total other income	369	350
Interest charges		
Long-term debt	1,633	1,633
Other interest	163	67
Allowance for borrowed funds used during construction	(5)	(5)
Total interest charges	1,791	1,695
Income from continuing operations	3,536	2,981
Income (Loss) from discontinued operations, net	76	(2)
Net income applicable to common stock	$ 3,612	$ 2,979

	Unaudited Three Months Ended March 31	
Consolidated Statements of Comprehensive Income	**2006**	**2005**
Net income	$ 3,612	$ 2,979
Other comprehensive income, net of tax	-	-
Comprehensive income	$ 3,612	$ 2,979
Basic earnings per share	$ 0.69	$ 0.58

Diluted earnings per share	$	0.68	$	0.56
Cash dividends declared per share	$	0.28	$	0.25
Weighted average common shares outstanding-basic		5,243		5,160
Weighted average common shares outstanding-diluted		5,319		5,301

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

GREEN MOUNTAIN POWER CORPORATION Consolidated Statements of Cash Flows	Unaudited For the Three Months Ended March 31 2006	 2005
Operating Activities:	(in thousands)	
Income from continuing operations	$ 3,536	$ 2,981
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	3,637	3,776
Dividends from associated companies	310	297
Equity in undistributed earnings of associated companies	(363)	(319)
Allowance for funds used during construction	(16)	(12)
Amortization of deferred purchased power costs	82	849
Deferred income tax expense, net of investment tax credit amortization	1,660	(700)
Deferred purchased power costs	(5,910)	1
Environmental and conservation deferrals, net	(649)	(308)
Share-based compensation	214	60
Changes in:		
Accounts receivable and accrued utility revenues	1,343	943
Prepayments, fuel and other current assets	143	502
Accounts payable and other current liabilities	1,719	(1,100)
Accrued income taxes payable and receivable	(4,702)	2,289
Other	260	674
Net cash provided by continuing operations	1,265	9,933
Operating cash flows from discontinued operations	76	(2)
Net cash provided by operating activities	1,341	9,931
Investing Activities:		
Construction expenditures	(4,028)	(3,684)
(Restriction)release of cash for renewable energy investments	105	(1)
Return of capital from associated companies	158	63
Investment in nonutility property	(59)	(49)
Net cash used in investing activities	(3,824)	(3,671)
Financing Activities:		
Payments on capital lease	(20)	(47)
Issuance of common stock	214	237
Short-term debt	-	(3,000)
Cash dividends	(1,471)	(1,291)
Net cash used in financing activities	(1,277)	(4,101)
Net increase in cash and cash equivalents	(3,759)	2,159
Cash and cash equivalents at beginning of period	6,500	1,720
Cash and cash equivalents at end of period	$ 2,741	$ 3,879
Supplemental Disclosure of Cash Flow Information:		
Cash paid year-to-date for:		
Interest	$ 1,139	$ 1,041

Income taxes	4,137	12
Non-cash construction additions	520	693
The accompanying notes are an integral part of these consolidated financial statements.		

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	Unaudited At March 31, 2006	At December 31, 2005
ASSETS	In thousands	
Utility plant		
Utility plant, at original cost	$ 349,821	$ 347,947
Less accumulated depreciation	125,634	122,924
Utility plant, net of accumulated depreciation	224,187	225,023
Property under capital lease	4,369	4,369
Construction work in progress	8,613	7,519
Total utility plant, net	237,169	236,911
Other investments		
Associated companies, at equity	9,932	10,036
Other investments	10,681	10,627
Total other investments	20,613	20,663
Current assets		
Cash and cash equivalents	2,741	6,500
Accounts receivable, less allowance for doubtful accounts of $500 and $484	19,109	19,594
Accrued utility revenues	6,432	7,291
Fuel, materials and supplies, average cost	6,333	6,360
Power supply derivative asset	8,407	15,342
Power supply regulatory asset	4,674	7,791
Prepayments and other current assets	1,318	1,434
Total current assets	49,014	64,312
Deferred charges		
Demand side management programs	5,470	5,835
Purchased power costs	7,634	1,812
Pine Street Barge Canal	12,776	12,861
Power supply regulatory asset	24,100	22,344
Other regulatory assets	5,560	5,809
Other deferred charges	3,201	3,068
Total deferred charges	58,741	51,729
Non-utility		
Property and equipment	246	246
Other assets	388	407
Total non-utility assets	634	653
Total assets	$ 366,171	$ 374,268

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	Unaudited At March 31, 2006	At December 31, 2005
CAPITALIZATION AND LIABILITIES	In thousands except share data	
Capitalization		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 6,079,397 and 6,060,962)	$ 20,265	$ 20,203
Additional paid-in capital	81,362	81,271
Retained earnings	38,005	35,864
Accumulated other comprehensive income	(3,263)	(3,263)
Treasury stock, at cost (827,639 shares)	(16,701)	(16,701)
Total common stock equity	119,668	117,374
Long-term debt, less current maturities	79,000	79,000
Total capitalization	198,668	196,374
Capital lease obligation	3,924	3,944
Current liabilities		
Current portion of long term debt	14,000	14,000
Accounts payable, trade and accrued liabilities	8,950	14,196
Accounts payable to associated companies	7,096	1,483
Accrued taxes	901	5,603
Power supply derivative liability	4,674	7,791
Power supply regulatory liability	8,407	15,342
Customer deposits	1,039	1,052
Interest accrued	1,871	1,137
Other	2,474	2,552
Total current liabilities	49,412	63,156
Deferred credits		
Power supply derivative liability	24,100	22,344
Accumulated deferred income taxes	29,822	28,092
Unamortized investment tax credits	2,209	2,280
Pine Street Barge Canal cleanup liability	5,504	6,096
Accumulated cost of removal	21,255	21,105
Deferred compensation	10,138	8,213
Other regulatory liabilities	7,113	6,513
Other deferred liabilities	11,728	13,777
Total deferred credits	111,869	108,420
COMMITMENTS AND CONTINGENCIES, Note 3		
Non-utility		
Net liabilities of discontinued segment	2,298	2,374
Total non-utility liabilities	2,298	2,374
Total capitalization and liabilities	$ 366,171	$ 374,268

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

Consolidated Statements of Retained Earnings	Unaudited Three Months Ended March 31	
In thousands	**2006**	**2005**
Balance - beginning of period	$ 35,864	$ 29,889
Net Income	3,612	2,979
Other adjustments	-	-
Cash Dividends-common stock	(1,471)	(1,291)
Balance - end of period	$ 38,005	$ 31,577

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

ITEM 1. NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES
It is our opinion that the financial information contained in this report reflects all normal, recurring adjustments necessary to present a fair statement of results for the periods reported, but such results are not necessarily indicative of results to be expected for the year due to the seasonal nature of our business and include other adjustments discussed elsewhere in this report necessary to reflect fairly the results of the interim periods. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission. However, the disclosures herein, when read with the Green Mountain Power Corporation (the "Company" or "GMP") annual report for 2005 filed on Form 10-K, are adequate to make the information presented not misleading. The preparation of financial statements in conformity with generally accepted accounting principles requires the use of estimates and assumptions that affect assets and liabilities, and revenues and expenses. Actual results could differ from such estimates.

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 Vermont Public Service Board ("VPSB"). The Vermont Department of Public Service ("DPS" or the "Department") is the public advocate for utility customers.

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. Revenues 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.

Revenues
The VPSB sets the rates we charge our customers for their electricity. Electricity sales to customers are based on monthly meter readings. Estimated unbilled revenues are recorded at the end of each monthly accounting period. In order to determine unbilled revenues, the Company makes various estimates including 1) energy generated, purchased and resold, 2) losses of energy over transmission and distribution lines, 3) kilowatt-hour usage by retail customer mix (residential, small commercial and industrial), and 4) average retail customer pricing rates.

The Company recognizes revenues from sales of utility construction and other services in retail revenues. To the extent that these revenues arise under long-term contracts, the Company records revenues and net income using the percentage of contract completion method.

Benefit Plans

The Company sponsors several qualified and nonqualified pension plans and other post-employment benefit plans covering current and former employees who meet certain eligibility criteria. The assumptions used to calculate the cost and obligations associated with these plans are determined on January 1 for the upcoming year. These assumptions are disclosed in the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2005 (the "Form 10-K"). The Company expects to contribute approximately $2.0 million to its defined benefit plans in 2006. During the three months ended March 31, 2006, GMP contributed $0.5 million to its defined benefit plans.

For the Three Months Ended March 31, 2006	Qualified Pension Plan	Supplemental Pension Plan	Post-Retirement Benefit Plan	Total
		In thousands		
Service cost	$ 319	$ 25	$ 81	$ 425
Interest cost	531	75	250	856
Expected return on plan assets	(669)	0	(250)	(919)
Amortization of prior service cost	0	0	81	81
Amortization of the transition obligation	31	19	(62)	(12)
Recognized net actuarial gain	100	12	63	175
Net periodic pension benefit cost	$ 312	$ 131	$ 163	$ 606

For the Three Months Ended March 31, 2005	Qualified Pension Plan	Supplemental Pension Plan	Post-Retirement Benefit Plan	Total
		In thousands		
Service cost	$ 221	$ 35	$ 77	$ 333
Interest cost	515	73	267	855
Expected return on plan assets	(603)	0	(236)	(839)
Amortization of prior service cost	43	9	(59)	(7)
Amortization of the transition obligation	0	0	83	83
Recognized net actuarial gain	49	6	56	111
Net periodic pension benefit cost	$ 225	$ 123	$ 188	$ 536

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 first quarter of 2006 and 2005 were $125,000 and $100,000, respectively.

Earnings Per Share

Basic earnings per share ("EPS") is calculated by dividing net income, by the weighted-average common shares outstanding for the period. Diluted EPS reflects the impact of the issuance of common shares for all potential dilutive common shares outstanding during the period, including stock options.

Reconciliation of income and shares used in computing fully diluted earnings per share	Three months ended March 31

In thousands		2006		2005
Net income applicable to common stock	$	3,612	$	2,979
Weighted average number of common shares-basic		5,243		5,160
Dilutive effect of stock options		76		141
Weighted average number of common shares-diluted		5,319		5,301

Stock-Based Compensation

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 has discontinued granting stock options.

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. 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. Accordingly, prior periods have not been restated.

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. Pursuant to SFAS 148, the Company has provided disclosure of pro-forma information regarding net income and earnings per share, using the allowed expense recognition guidelines of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees.

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 three months ended March 31, 2006 and 2005, the Company granted 400 shares and 153 shares of unrestricted stock with a weighted average grant date fair value of $29.00 per share and $29.17 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 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. Stock Unit awards may be deferred and earn the equivalent of dividends 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 $214,000 and $60,000 for the three months ended 2006 and 2005, respectively. A summary of stock unit awards activity follows:

Stock awards	Total Stock Awards	Vested Stock Awards	Non-vested Stock Awards	Average Grant-date fair value	Aggregate Intrinsic Value	Shares returned for income tax withholding	Compensation cost recognized
Outstanding at December 31, 2005	58,566	7,166	51,400	$ 27.12	$ 1,588,310	-	$ -

Shares granted or dividend equivalents earned	400	400	-	29.00	11,600	249	11,598
Vested	-	17,600	(17,600)	29.10	512,160	5,455	202,092
Issued	(20,540)	(20,540)	-	24.13	495,630		
Outstanding at March 31, 2006	38,426	4,626	33,800	$ 28.69	$ 1,102,442		$ 213,690

Approximately $369,000 of unrecognized compensation exists at March 31, 2006, with a weighted average accrual period of 11 months remaining. The amount capitalized as part of the cost of assets was approximately $1,623.

A summary of stock option activity follows:

	Total Options	Weighted Average Price	Aggregate Intrinsic Value	Average Contractual Life in years
Outstanding and exercisable at December 31, 2005	146,600	$ 10.90	$ 2,586,686	
Granted	-	-		
Exercised	4,500	$ 10.22	83,248	
Forfeited	-	-		
Outstanding and exercisable at March 31, 2006	142,100	$ 10.92	$ 2,504,249	4.9

Cash received from the exercise of options totaled approximately $44,000, and the Company recognized a reduction in income tax liability of approximately $55,000. 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.

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.

Pro-forma net income In thousands, except per share amounts	Three months ended March 31 2006	 2005
Net income reported	$ 3,612	$ 2,979
Pro-forma net income	3,612	2,979
Share based compensation, net of tax included in net income	127	36
Share based compensation, net of tax not included in net income	-	-
Earnings per share		
As reported-basic	$ 0.69	$ 0.58
Pro-forma basic	0.69	0.58
As reported-diluted	0.68	0.56
Pro-forma diluted	0.68	0.56

Unregulated operations

Our wholly owned subsidiaries include GMP Real Estate Corporation and Green Mountain Power Investment Company ("GMPIC"). We also have a rental water heater program that is not regulated by the VPSB. The results of these subsidiaries, and the Company's unregulated rental water heater program, are included in equity in earnings of affiliates and non-utility operations in the Other Income (Deductions) section of the Consolidated Statements of Income.

Discontinued Operations
The Company accounts for its wholly-owned subsidiary, Northern Water Resources, Inc. ("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. Substantially all of NWR's investments have been written off, except for associated deferred tax amounts, net of applicable valuation allowances.

2. INVESTMENT IN ASSOCIATED COMPANIES
We recognize net income from our affiliates (companies in which we have ownership interests) listed below based on our percentage ownership (equity method).

Vermont Electric Power Company, Inc. ("VELCO")
Percent ownership: 29.2% common
30.0% preferred

VELCO and its wholly-owned subsidiary, Vermont Electric Transmission Company, own and operate 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 up to $25 million in VELCO through 2008 in support of various transmission projects.

Summarized unaudited financial information for VELCO is as follows:

	Three Months Ended March 31	
In thousands	2006	2005
Gross Revenue	$ 8,987	$ 7,982
Net Income	771	730
Equity in Net Income	239	210
Amounts due to VELCO	4,071	4,015

VELCO provided transmission services to the Company (reflected as transmission expenses in the accompanying Consolidated Statements of Income) amounting to $1.8 million and $3.4 million in the first quarter of 2006 and 2005, respectively.

Included in the Company’s retail and other revenues are construction services of approximately $91,000 and $1,000 billed to VELCO in the first quarter of 2006 and 2005, respectively.

Vermont Yankee Nuclear Power Corporation ("VYNPC")
Percent ownership: 33.6% common

Summarized unaudited financial information for VYNPC follows:

Vermont Yankee Nuclear Power Corporation
Percent ownership: 33.6

Three Months Ended

	March 31	
In thousands	2006	2005
Gross Revenue	$ 44,347	$ 42,349
Net Income Applicable to Common Stock	173	162
Equity in Net Income	58	54
Amounts due to VYNPC	3,023	2,741

On July 31, 2002, VYNPC announced that the sale of the Vermont Yankee nuclear power plant to Entergy Nuclear Vermont Yankee, LLC ("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.

ENVY has announced that, under current operating parameters, it will exhaust the capacity of its existing nuclear waste storage pool in 2007 or 2008 and will need to store nuclear waste in so-called "dry fuel storage" facilities to be constructed on the site. ENVY received approval from the Vermont legislature in 2005 and the VPSB in April 2006 to construct and use such dry fuel storage facilities.

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

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

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. The plant production will now be gradually increased and monitored as the plant progresses to its new full-power output of approximately 640 megawatts. After the Vermont Yankee nuclear plant uprating is completed, our percentage of energy output under Vermont Yankee's contract with ENVY would decline proportionately such that we would receive the same quantity of energy from the plant. In the event that ENVY were later derated, then our rights to energy output could decline proportionately to the derating. If this were to occur, we estimate it would have a material adverse effect on power supply costs. In this event we would seek recovery of these costs from the VPSB.

3. COMMITMENTS AND CONTINGENCIES
Environmental Matters
The electric industry typically uses or generates a range of potentially hazardous products in its operations. We must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with these requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations.

Pine Street Barge Canal Superfund Site

In 1999, the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal Superfund site in Burlington, Vermont, known as the "Pine Street Barge Canal." The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. We have estimated total future costs of the Company's future obligations under the consent decree to be approximately $6.1 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have recorded a regulatory asset of $12.8 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.

Rates

Management believes that fair regulatory treatment, including adequate and timely rate relief, is required to maintain the Company's financial strength**.**

Retail Rate Cases

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, and allowed the Company to defer power supply expenses of $2.1 million in the first quarter of 2006.

On April 14, 2006, the Company petitioned to increase retail rates by 11.95 percent the ("2006 Retail Rate Filing"). We expect the VPSB to issue a final order on this rate increase request no later than December 29, 2006, and new rates to be effective January 1, 2007. The rate increase is required to recover costs of providing electric service to our customers. Approximately 88 percent of the increase is due to rising power costs and the remaining 12 percent is due to increased transmission costs. The power cost increase is driven largely by the need to replace the Morgan Stanley contract expiring at the end of this year, and by the higher-cost, post-Katrina wholesale market. The increased transmission costs are largely attributable to reliability-related projects planned or under construction within the state and region. If the VPSB does not allow our full rate requirements, GMP estimates that for every 1 percent shortfall in rates, the financial impact would be a $2.0 million reduction in pre-tax earnings.

On April 14, 2006, the Company also filed for approval of an Alternative Regulation Plan. A principal component of the Plan include a power supply adjustment mechanism that will allow the Company to adjust rates on a quarterly basis to reflect power supply cost changes in excess of $400,000 per quarter. The Plan also proposes 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, if approved, would allow the Company to earn up to 75 basis points above its allowed return on equity and would allow the Company to recover earnings shortfalls in excess of 100 basis points below its allowed return on equity. The Plan will also create opportunities and incentives for the Company to become more efficient, improve customer service, remove incentives to benefit from increased electricity sales, streamline cost recovery, share efficiency savings with customers, increase credit quality, and reduce regulatory and borrowing costs borne by customers. In addition, the Company proposes directing additional funding to the Company's low income assistance programs. The Company expects the VPSB to rule on the Plan on or before April 15, 2007. Under Vermont law, an alternative regulation plan may become effective 30 days after VPSB approval.

Other Regulatory Matters

Power Supply Risks and Contingencies

The Company meets more than 90 percent of its customer demand through a series of long-term physical and financial contracts. The Company’s most significant power supply contracts are the Hydro Quebec Vermont Joint Owners ("VJO") Contract (the "VJO Contract") and the Vermont Yankee Nuclear Power Corporation ("VYNPC") Contract (the "VYNPC Contract"), which together cover approximately 75 percent of our retail load. The Company has also entered into a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") designed to manage wholesale electricity price risks associated with changing fossil fuel prices. The Morgan Stanley Contract supplies approximately an additional 17 percent of our load and expires December 31, 2006. See Power Contract Commitments and Related Risks - JPMorgan Energy Services, Management’s Discussion and Analysis.

There are uncertainties regarding risks of delivery under various contracts that the Company relies upon to satisfy customer demand for electricity. If the Company’s entitlements for electricity are not realized due to delivery risks, the exercise of options that reduce our entitlements under certain contracts, or for other reasons, then the Company would purchase replacement energy and be subject to volatile energy prices that exist in the wholesale markets that could materially affect our operating results and financial condition.

The Company remains exposed to wholesale energy prices for approximately 10 percent of its load. Wholesale energy price volatility can also adversely impact margins on incremental sales. Energy price risk remains one of the Company’s most significant risks and can have a material adverse effect on the Company’s operating results and financial condition.

Our outage risks are generally a function of how much energy we receive from a particular source, the price of energy received from that source, whether the energy is unrelated to any specific operating plant (low-risk system power) or is dependent upon a particular power plant operating (high-risk), and the dependability of the transmission delivery system for that source. Counterparty credit quality also impacts risk. The Company's most significant power supply contract counterparties and certain associated risk attributes are summarized in the following table:

Contract	Counterparty	Investment Grade	System Power or Plant	Approximate Percent Load	Approximate Amount $ Per MWh
VYNPC	ENVY (through VYNPC)	No	VY Plant	35 - 40%	$40
VJO	Hydro Quebec	Yes	System Power	30 - 35%	$70
Morgan Stanley	Morgan Stanley	Yes	System Power	16%	Confidential*

**Morgan Stanley Contract terms are subject to a confidentiality agreement.*

Other Legal Matters

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville hydro-electric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, alleging that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company received VPSB approval for, and has made additional dam improvements at, the facility. The Company and the DPS have stipulated to a penalty amount of $50,000. The stipulation was approved by the VPSB on July 20, 2005 and the stipulated $50,000 penalty amount has been paid. In addition, numerous owners of shoreline property on Joe's Pond have filed a lawsuit in Vermont superior court seeking damages for property damage allegedly caused by the Company's negligent conduct in making dam improvements and operating the dam facilities. The Company is defending against these claims. The Company does not expect the litigation to result in a material adverse effect on its operating results or financial condition.

4. DERIVATIVE INSTRUMENTS

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

SFAS 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. Absent the accounting order, SFAS 133 would require that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. 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.

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 a derivative and is effective through 2015. From time to time, we use forward contracts to hedge the 9701 agreement. If the Company were to terminate or sell any of its derivative contracts, it would immediately record the gain or loss on that contract. For derivatives held to maturity, the earnings impact would be recorded in the period that the derivative is sold or matures.

The Morgan Stanley Contract is used to hedge against increases in fossil fuel prices. The Morgan Stanley Contract is a derivative and expires December 31, 2006.

At March 31, 2006, the Company had a power supply derivative liability of $24.1 million recorded in deferred credits and $4.7 million recorded in current liabilities totaling the $28.8 million fair value of the 9701 agreement. Also at March 31, 2006, the Company had a power supply derivative asset of $8.4 million, reflecting the fair value of the Morgan Stanley Contract and the fair value of a forward sale contract. Corresponding regulatory assets and regulatory liabilities total $28.8 million and $8.4 million, respectively. Amounts due during the next twelve months are classified in current assets and current liabilities. At December 31, 2005, the Company had a liability of $30.1 million, reflecting the fair value of the 9701 agreement, and an asset of $15.3 million, reflecting the fair value of the Morgan Stanley Contract. Corresponding regulatory assets and regulatory liabilities total $30.1 million and $15.3 million, respectively. Amounts due during 2006 are classified in current assets and current liabilities.

5. SEGMENTS AND RELATED INFORMATION

The Company's electric utility operation is its only operating segment. The electric utility is engaged in the procurement, generation, distribution and sale of electrical energy in the State of Vermont and also reports the results of GMP Real Estate and the rental water heater program in the Other Income section in the Consolidated Statement of Income.

6. NEW ACCOUNTING STANDARDS

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS 123R, which revises SFAS 123 and supersedes APB 25 and its related implementation guidance. SFAS 123R focuses primarily on accounting for share-based payments to employees in exchange for services, and it requires entities to recognize compensation expense for these payments. The cost for equity-based awards is expensed based on their grant date fair value, and liability awards are expensed based on their fair value, which is re-measured each reporting period. The pro forma disclosure previously permitted under SFAS 123 is no longer an alternative to financial statement recognition. The Company uses the fair value method for share-based payment awards and predicts that this new standard will not have a material impact on its financial position, its results of operations or its liquidity.

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 carry-forwards). 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.

On May 25, 2005, the Financial Accounting Standards Board ("FASB") issued Statement No. 154, *Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3* ("SFAS 154"). This Statement replaces APB Opinion No. 20, Accounting Changes, and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements*, and changes the requirements for the accounting for and reporting of a change in accounting principles. This Statement applies to all voluntary changes in accounting principle and changes required by an accounting pronouncement in the instance that the pronouncement does not include specific transition provision. Effective January 1, 2006, the adoption of SFAS 154 had no effect on the financial statements of the Company.

On March 31, 2006, the FASB issued a proposal that would require recognition of the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, on the balance sheet measured as the difference between the fair value of plan assets and obligations as of each reporting period. Statement of Financial Accounting Standard (SFAS) No. 87, "Employers' Accounting for Pensions" (SFAS 87) and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106) allow for recognition of an asset or liability that almost always differs from its funded position since delayed recognition of certain changes is permitted. Under this proposal, actuarial gains and losses and prior service costs and credits that arise during the period but, pursuant to SFAS 87 and 106 are not yet recognized as components of net periodic benefit cost, would be recognized as a component of Other Comprehensive Income, net of tax. Such amounts would be adjusted as they are subsequently amortized as a component of net periodic benefit cost. The proposal also would require an adjustment to the opening balance of retained earnings, net of tax, for any transition obligation remaining from the initial application of SFAS 87 and 106. Such amounts would then not subsequently be amortized as a component of net periodic benefit cost.

The requirements to measure the plan assets and obligations at fair value would be effective for fiscal years beginning after December 15, 2006. The remaining changes would be effective for fiscal years ended after December 15, 2006. The Company is currently evaluating the potential impact of this proposal on the Condensed Consolidated Financial Statements. If the Company does not succeed in obtaining an accounting order to defer the effects, based on current estimates, Accumulated Other Comprehensive Income would increase by $5.2 million, net of tax, and Retained Earnings would decrease by $1.5 million, net of tax.

7. SUBSEQUENT EVENT

JPMorgan Ventures Energy Corporation - On April 21, 2006, the Company entered into a contract with JPMorgan Ventures Energy Corporation to purchase 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. JPMorgan Ventures Energy Corporation's obligations under the contract are subject to a guarantee of $25 million from JPMorgan Chase & Co., its parent company. Following expiration of the Morgan Stanley Contract and after commencement of the contract with JPMorgan Ventures Energy Corporation, the Company will have approximately 100,000 mWh of remaining off-peak load exposed to market prices during the period 2007 - 2010. 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 open position represents approximately 5 percent of Company load, and because it is off-peak is subject to less than average pricing volatility. The replacement power costs reflected in the JPMorgan agreement and the forecasted costs of the Company's remaining open position are substantially included in the Company's 2006 Retail Rate Filing.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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
- 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

Executive Overview

Green Mountain Power Corporation (the "Company") typically generates most of its earnings from retail electricity sales. Our retail electricity sales typically grow 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 is regulated and cannot adjust prices of retail electricity sales without regulatory approval from the Vermont Public Service Board ("VPSB").

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 2005 was comparatively low, at approximately 48 percent of 2005 earnings from continuing operations. We expect to grow our dividend payout ratio to the middle of a payout range of between 50 and 70 percent over the next five years, in line with other electric utilities having similar risk profiles, so long as financial and operating results permit.

Fair regulatory treatment is fundamental to maintaining the Company’s financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders in order to attract capital. The Company’s allowed rate of return on its regulated operations is currently capped at 10.5 percent, reduced by amounts normally excluded for purposes of setting rates and is determined by the VPSB. Nearly all of the Company’s continuing operations are treated for ratemaking purposes as regulated operations. The Company’s 2005 return on equity was 9.85 percent reflecting the exclusions mentioned above. These exclusions also make it unlikely that the Company’s operating results will achieve its allowed rate of return while its earnings are subject to the earnings cap. The Company is currently operating 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, a plan for full recovery of the Company’s principal regulatory assets, and an improved opportunity to earn a fair rate of return.

Power supply expenses were equivalent to approximately 63 percent of total operating expenses in the first quarter of 2006. Therefore, any significant increase in the cost of our power supply resources would likely require the Company to seek a rate increase. The Company filed a retail rate case requesting a rate increase of 11.95 percent on April 14, 2006, effective for January 1, 2007, partially as a result of the need to replace an expiring power supply contract. 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.

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

In this section, we explain the general financial condition and the results of operations for the Company and its subsidiaries. This explanation includes:

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

Management believes its most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate; the manner in which we account for certain power supply arrangements that qualify as derivatives; the assumptions that we make regarding defined benefit plans and contingency reserves; and revenue recognition, particularly as it relates to unbilled and deferred revenues. These accounting policies, among others, affect the Company's significant judgments and estimates used in the preparation of its consolidated financial statements.

We address these items in more detail below.

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

As you read this section it may be helpful to refer to the consolidated financial statements and notes in Part I - ITEM 1.

RESULTS OF OPERATIONS

Earnings Summary - Overview

In this section, we discuss our earnings and the principal factors affecting them.

Total basic earnings per share of Common Stock	Three months ended March 31			
		2006		2005
Utility business	$	0.68	$	0.57
Unregulated businesses		0.01		0.01
Earnings per share of common stock	$	0.69	$	0.58

Basic earnings per share	$	0.69	$	0.58
Diluted earnings per share	$	0.68	$	0.56

Operating Results
The Company had consolidated earnings of $0.68 per share of common stock, diluted, for the first quarter of 2006 compared with consolidated earnings of $0.56 per share of common stock, diluted, for the same period in 2005.

Earnings increased in the first quarter of 2006 primarily as a result of increase in gross margins resulted from market sales of excess electricity at prices above our underlying costs to purchase the energy. The Company's power supply resources exceeded customer demand during the first quarter of 2006 due to an unusually mild and wet winter and because the Company elected to exercise contract rights to increase deliveries at below market prices from one of its suppliers during 2006. Increased precipitation caused our hydro generation output to increase substantially in 2006 compared with the same quarter last year. The minimal increase in power supply costs in 2006 resulted from added production from our hydro power plants that replaced higher market purchases made during the first quarter of 2005, and offset most of the increased costs from other energy contracts in 2006.

The Company has long-term, essentially fixed-price, power supply contracts that cover over 90 percent of customer demand under normal weather conditions. Therefore, in the first quarter of 2006, power supply expenses increased by $86,000 compared with the first quarter of 2005 because the cost of additional purchases from independent power producers and under our contract entitlements in 2006 was offset by additional production from company owned hydro facilities that replaced energy purchased in the wholesale energy markets during 2005.

Retail operating revenue for the first quarter of 2006 decreased by $470,000 compared with the same period in 2005, reflecting the effects of reduced residential and commercial/industrial sales of electricity as a result of an unusually mild winter. The revenue impact from reduced sales was partially offset by a 0.9 percent rate increase authorized by the Vermont Public Service Board which generated $500,000 in additional revenues during the first quarter of 2006. Sales to residential and large commercial and industrial customers decreased by 2.7 percent and 5.4 percent, respectively, compared with the first quarter in 2005. By contrast, sales to small commercial and industrial customers increased by 0.6 percent in the first quarter of 2006 compared with the same quarter last year. Total retail megawatt hours sales of electricity decreased by 2.6 percent in the first quarter of 2006, compared with the same period in 2005. Wholesale revenues in the first quarter of 2006 increased by $3.2 million compared to the same quarter in 2005. Wholesale revenues increased because we sold the excess supplies discussed above in the wholesale energy market. We sold some of our expected energy excess for March 2006 late last year when prices were very high.

Power supply expenses increased by $86,000 in the first quarter of 2006 compared with the same quarter in 2005 because the cost of additional purchases from independent power producers and under the contract entitlements in 2006 was offset by additional production from Company-owned hydro facilities that replaced energy purchased in the wholesale energy markets during 2005.

Other operating expenses increased $575,000 in the first three months of 2006 compared with the same period of 2005 due primarily to an increase in distribution and customer account expenses.

Transmission expenses increased by $759,000 in the first quarter of 2006 compared with the same period last year, primarily as a result of an increase in Vermont transmission investment and in our share of Vermont transmission expenses because our loads have increased relative to other Vermont utilities.

Maintenance expenses increased by $470,000 in the first three months of 2006 compared with the same period of 2005 primarily as a result of a winter wind storm causing additional payroll and supply costs to be incurred.

OPERATING REVENUES AND MWH SALES

Our revenues from operations, megawatt hour ("MWh") sales and average number of customers for the three months ended March 31, 2006 and 2005 are summarized below:

	Three months ended March 31			
Dollars in thousands		2006		2005
Operating revenues				
Retail	$	53,950	$	54,420
Sales for Resale		7,026		3,828
Total Operating Revenues	$	60,976	$	58,248
MWh Sales-Retail		502,789		516,022
MWh Sales for Resale		97,857		65,812
Total MWh Sales		600,646		581,834

Average Number of Customers	Three months ended March 31	
	2006	2005
Residential	77,942	76,316
Commercial and Industrial	13,970	13,658
Other	62	62
Total Number of Customers	91,974	90,036

Revenues

Total operating revenues in the first quarter of 2006 increased by $2.7 million or 4.7 percent from the same period in 2005, due to an increase in wholesale revenues of $3.2 million partially offset by a decrease in retail revenues of $470,000.

Retail operating revenues for the first quarter of 2006 decreased $470,000 or 0.9 percent compared with the same period in 2005, reflecting decreased megawatt hour sales of electricity caused by warmer winter weather. Total retail megawatt hour sales of electricity decreased by 2.6 percent in the first quarter of 2006, compared with the same period in 2005.

The Company recognizes revenues from sales of utility construction services in retail revenues. Revenues from these activities amounted to $402,000 in the first quarter of 2006 compared with $183,000 in the same period last year.

Customer Concentration Risk

The Company’s major industrial customer, International Business Machines ("IBM"), accounted for 14.2 percent, 15.3 percent and 16.2 percent of retail revenue for 2006 year to date, and the years ended 2005 and 2004, respectively. The Company currently estimates, based on current forward energy prices, that a hypothetical shutdown of the IBM facility would not require any rate increase, inclusive of projected related declines in sales to residential and commercial customers. This effect occurs because forward energy prices are well above the price at which we sell electricity to IBM.

OPERATING EXPENSES

Power supply expenses

Power supply expenses increased $86,000 or 0.2 percent in the first quarter of 2006 compared with the same period in 2005, as increased purchases from small power producers, Hydro Quebec and VYNPC were substantially offset by declines in market purchases from ISO-NE.

Power supply expenses from VYNPC increased $397,000 or 4.6 percent during the first quarter of 2006 compared with the same period of 2005, primarily due to an increase in output from the Vermont Yankee nuclear power plant purchased under our contract with VYNPC.

Company-owned generation expenses decreased $196,000 or 12.7 percent in the first quarter of 2006 compared with the same period in 2005, primarily due to decreased production at a joint-owned generation facility.

The cost of power that we purchased from other companies decreased $115,000 or 0.5 percent in the first quarter of 2006 compared with the same period in 2005. This was primarily due to decreased market purchases made possible because of increased hydro production arising from a mild winter with greater than normal precipitation that more than offset increased production from independent power producers that the Company must purchase under federal mandates and the Company's exercise of an option to increase energy deliveries from Hydro Quebec.

Under the Public Utility Regulatory Policy Act of 1978 ("PURPA"), the Company must purchase the output of plants governed by this act at specific rates for specified periods of time. These specified rates are typically the highest contract rates of any contracted resources that the Company purchases. Approximately half of the output of these plants is hydro and in the first quarter of 2006, higher than normal precipitation resulted in an increase of $1.7 million in purchases from these independent producer plants.

Under the Vermont Joint Owners (including the Company), contract with Hydro Quebec, the Company exercised one of its remaining two options to increase the load factor to 80 percent from 75 percent in November 2005. Hydro Quebec exercised the first of its options under this same contract to decrease the load factor from 75 percent to 65 percent in November 2004 for the period ending October 31, 2005. As a result, the Company received approximately 25,000 extra megawatt hours ("mWh") in 2006 at an average price of approximately $30 per mWh, well below wholesale market prices.

The Independent System Operator for New England ("ISO-NE") was created to manage the New England power pool. 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. Transmission projects, such as the recently approved Northwest Reliability Project ("NRP"), will reduce congestion when they are completed. The NRP is not expected to be completed prior to 2007. Even though Vermont utilities share a zone price for specific energy resources, congestion can cause a material difference to arise between the credit received at a generating point or node, (for example, entitlements to Vermont Yankee at the Vermont Yankee node) and the price that must be paid to serve Vermont load. ISO-NE allocates congestion charges to New England utilities according to its load model results.

ISO-NE supports locational capacity payments ("LICAP") to generators in an effort to differentiate the price generators receive for capacity at different locations within New England. ISO-NE believes that proposed higher capacity payments in constrained areas will encourage the development of new generation where needed. ISO-NE has petitioned FERC for approval of LICAP at levels that are expected to result in substantially higher capacity payments to generators beginning January 1, 2006. The changes have been disputed by numerous parties for a variety of reasons. FERC has not yet approved ISO-NE's LICAP proposal. In October 2005, FERC initiated a settlement process to consider alternatives to the LICAP proposal Under ISO-NE's LICAP proposal, Vermont is expected to fare better than many New England states since Vermont has not restructured and many of its utilities, including the Company, have specified power supply resources that meet their present needs. Therefore, requirements for capacity in Vermont would largely consist of obtaining resources for incremental as opposed to existing load. Even incrementally, future LICAP amounts for load growth beyond 2006 could be material, and if so, would be expected to increase Company rate requirements accordingly. Based on the current ISO-NE proposal, the Company estimates that the 2007 impact of LICAP price increases would raise our power supply expenses by approximately $1 million, and those costs are included in the Company's 2006 Retail Rate Filing.

Other operating expenses
Other operating expenses increased $575,000 or 11.8 percent in the first quarter of 2006 compared with the same period in 2005 due primarily to an increase in distribution and customer account expenses.

Transmission expenses
Transmission expenses increased by approximately $759,000 or 18.2 percent for the three months ended March 31, 2006 compared with the same period in 2005, primarily as a result of an increase in Vermont transmission investment and in our share of Vermont transmission expense because our loads have increased relative to other Vermont utilities.

Maintenance expenses
Maintenance expenses increased by $470,000 or 20.0 percent in the first three months of 2006 compared with the same period of 2005 primarily as a result of a winter wind storm causing additional payroll and supply costs to be incurred.

Depreciation and amortization expenses
Depreciation and amortization expenses for the quarter ended March 31, 2006 decreased $139,000 or 3.7 percent compared with the same period in 2005, reflecting a decrease in the depreciation of utility plant reflecting an updated depreciation study.

Taxes other than income taxes
Other tax expense for the first quarter of 2006 decreased by $11,000 or 0.6 percent compared with the same period in 2005 due to decreases in gross receipts tax.

Income taxes
Income taxes increased $356,000 or 21.2 percent in the first quarter of 2006 compared with the same period in 2005 due to an increase in pretax book income.

Interest Charges
Interest charges increased $96,000 or 5.7 percent in the first quarter of 2006 compared with the same period in 2005, due to an increase in interest expense on a tax obligation.

LIQUIDITY AND CAPITAL RESOURCES
At December 31, 2005, we had cash and cash equivalents of $6.5 million. In the first three months of 2006, cash and cash equivalents decreased to $2.7 million. Operating cash flows decreased by $8.6 million from the same period last year primarily as the result of increased working capital needs and payments for estimated income taxes. Net cash used by investing activities amounted to $3.8 million, principally for investments to construct utility plant.

The Company's 2006 Retail Rate Filing requests an increase in rates of 11.95 percent. Each percentage point represents approximately $2 million in pre-tax cash flow.

We expect to spend approximately $20.1 million during the next nine months of 2006, primarily for improvements in transmission, distribution and generation plant, and environmental expenditures. The Company plans to invest up to $25 million in VELCO through 2008 in support of the NRP and other transmission projects, including a $4.8 million investment made in the last quarter of 2004. Our investment projections for VELCO have increased from previous estimates primarily as a result of increases in VELCO's cost estimates for the NRP.

On February 27, 2006, the annual dividend rate was increased from $1.00 to $1.12 per share, a payout ratio of approximately 48 percent based on 2005 earnings from continuing operations. The Company expects to increase the dividend on a consistent basis in the first quarter of each year to the middle of a payout ratio that falls between 50 percent and 70 percent of anticipated earnings, so long as financial and operating results permit. We believe this payout ratio to be consistent with that of other electric utilities having similar risk profiles.

We expect most of our construction expenditures and dividends to be financed by net cash provided by operating activities. Material risks to cash flow from operations include increases in net power costs, regulatory risk, and unfavorable economic conditions. We anticipate that we will issue long-term debt of up to $30 million in 2006 for scheduled first mortgage bond redemptions of $14 million and to finance increased investment in VELCO and generation. The Company has no plans at present to issue additional equity and seeks to maintain equity at between fifty and fifty-five percent of its capital structure.

During June 2005, the Company renegotiated a 364-day revolving credit agreement with Bank of America, joined by Sovereign Bank (the "BOA-Sovereign Agreement"). The BOA-Sovereign Agreement is for $30.0 million, unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. The Company has negotiated a five year replacement revolving credit facility of $30 million with Sovereign Bank and Key Bank effective June 14, 2006, subject to VPSB approval of the facility. In the event that approval is not received prior to the expiration of the BOA-Sovereign Agreement, the Company will utilize a short-term borrowing facility with Sovereign Bank and Key Bank. Other significant changes to the revolving credit facility include the elimination of any material adverse change and material adverse effect clauses as pre-conditions for borrowing under the facility.

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

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

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

The following table presents a summary of certain material contractual obligations existing as of March 31, 2006, for which undiscounted future annual payments are shown.

	Payments Due by Period				
At March 31, 2006	**Total**	**2006**	**2007 and 2008**	**2009 and 2010**	**After 2011**
			(In thousands)		
Long-term debt	$ 93,000	$ 14,000	$ -	$ -	$ 79,000
Interest on long-term debt	62,640	5,538	11,068	11,068	34,966
Capital lease obligations	3,943	475	771	771	1,927
Hydro-Quebec power supply contracts	506,063	38,467	103,020	103,993	260,583
Morgan Stanley Contract	7,573	7,573	-	-	-
Independent Power Producers	147,011	11,130	33,285	33,285	69,312
Stony Brook contract	26,154	1,521	3,480	3,541	17,612
VYNPC PPA	201,590	24,498	64,144	69,811	43,137
Benefit plan contributions	19,500	1,500	4,000	4,000	10,000
VELCO capital contributions	25,230	15,660	9,570	-	-

Total	$ 1,092,705	$ 120,363	$ 229,338	$ 226,467	$ 516,537

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

Off-Balance Sheet Arrangements

The Company does not use off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets through special purpose entities.

Other Commitments

We have material power supply commitments that are discussed in detail under the captions "Power Contract Commitments and Related Risks" and "Power Supply Expenses." We also own an equity interest in VELCO, which requires the Company to contribute capital when required and to pay a portion of VELCO’s operating costs, including its debt service costs.

ITEM 3.QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Future Outlook - Competition, Legislation and Restructuring

The electric utility business continues to experience rapid and substantial changes. These changes are the result of the following trends:

- disparity in electric rates, transmission, and generating capacity among and within various regions of the country;
- improvements in generation efficiency;
- consolidation through business combinations;
- new regulations and legislation intended to foster competition;
- changes in rules governing wholesale electricity markets; and
- increasing volatility of wholesale market prices for electricity.

Vermont is the only state in the New England region that has not adopted some form of electric industry restructuring. The Vermont legislature enacted a bill that would impose renewable portfolio standards ("RPS") on Vermont electric distribution utilities. The bill currently contemplates that, effective January 1, 2013, distribution utilities will be required to supply all load growth for 2005 - 2013 with "renewable" energy supply, as defined in the bill. The bill provides the alternative that if in-state renewable generation sufficient to supply statewide load growth for 2005 - 2013 becomes operational before 2012, and if Vermont distribution utilities acquire the output of these facilities, the RPS requirement would be avoided.

Power Contract Commitments and Related Risks

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 or sell the difference into a marketplace that has experienced volatile energy prices. Volatility and market price trends also make it more difficult to extend or enter into new power supply contracts at prices that avoid the need for rate relief.

We have developed a power supply portfolio that meets approximately 90 percent of our estimated customer demand ("load") requirements through 2006. Our power supply contracts and resources significantly reduce the Company's exposure to volatility in wholesale energy market prices. The Company remains exposed to very volatile energy markets for the remaining 10 percent of its load requirements, as well as congestion, line loss and other ancillary service charges allocated to New England utilities by ISO-NE.

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

On April 14, 2006, the Company petitioned to increase retail rates by 11.95 percent, the (“2006 Retail Rate Filing”). We expect the VPSB to issue a final order on this rate increase request no later than December 29, 2006, and new rates to be effective January 1, 2007. The rate increase is required to recover costs of providing electric service to our customers. Approximately 88 percent of the increase is due to rising power costs and the remaining 12 percent is due to increased transmission costs. The power cost increase is driven largely by the need to replace the Morgan Stanley contract expiring at the end of this year, and by the higher-cost, post-Katrina wholesale market. The increased transmission costs are largely attributable to reliability-related projects planned or under construction within the state and region. If the VPSB does not allow our full rate requirements, GMP estimates that for every 1 percent shortfall in rates, the financial impact would be a $2.0 million reduction in pre-tax earnings.

On April 14, 2006, the Company also filed for approval of an Alternative Regulation Plan. A principal component of the Plan includes a power supply adjustment mechanism that will allow the Company to adjust rates on a quarterly basis to reflect power supply cost changes in excess of $400,000 per quarter. The Plan also proposes 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, if approved, would allow the Company to earn up to 75 basis points above its allowed return on equity and would allow the Company to recover earnings shortfalls in excess of 100 basis points below its allowed return on equity. The Plan will also create opportunities and incentives for the Company to become more efficient, improve customer service, remove incentives to benefit from increased electricity sales, streamline cost recovery, share efficiency savings with customers, increase credit quality, and reduce regulatory and borrowing costs borne by customers. In addition, the Company proposes directing additional funding to the Company’s low income assistance programs. The Company expects the VPSB to rule on the Plan on or before April 15, 2007. Under Vermont law, an alternative regulation plan may become effective 30 days after VPSB approval.

Vermont Yankee - We have a 20 percent entitlement in Vermont Yankee plant output sold by Entergy to Vermont Yankee Nuclear Power Corporation ("VYNPC"), through a long-term purchase contract with VYNPC (the "VYNPC Contract"). We generally purchase between 35 and 40 percent of our annual load requirements from VYNPC at rates that are presently well below market. We are responsible for the purchase of replacement power to serve our load requirements when the plant is not operating due to scheduled or unscheduled outages. In the first three months of 2006, we purchased $9.1 million from VYNPC based on our entitlement share of plant output, compared to $8.7 million for the same period in 2005, reflecting the uprated capacity of the plant to produce energy. These additional amounts are purchased at market prices by the Company.

Hydro Quebec - We purchase varying amounts of power from Hydro Quebec under the Vermont Joint Owners ("VJO") Contract negotiated between the Company and Hydro Quebec. There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro Quebec, the remaining VJO participants, including the Company, must "step-up" to the defaulting party's share on a pro rata basis. The Company is not aware of any instance where this provision has been invoked by Hydro Quebec. In the first three months of 2006, we purchased $13.1 million of energy and related capacity from Hydro Quebec, compared to $12.3 million for the same period in 2005.

Under the VJO Contract, Hydro Quebec had the right to reduce the load factor from 75 percent to 65 percent a total three times over the life of the contract. Hydro Quebec exercised its third and last option in 2004 for deliveries occurring principally during 2005. Hydro Quebec retains the right to reduce the load factor by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Quebec. The utilities that comprise the

VJO retain two options to increase or reduce the load factor by 5 percent under the VJO Contract and exercised the first of these options to increase deliveries occurring principally between November 1, 2005 and October 30, 2006. The option will provide approximately 50,000 additional off-peak megawatt hours of supply.

Morgan Stanley - We purchase approximately 17 percent of our load requirements under a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"), designed to manage some of the price risks associated with changing fossil fuel prices. The Morgan Stanley Contract price is substantially below current market prices and expires on December 31, 2006.

Subsequent Event

JPMorgan Ventures Energy Corporation - On April 21, 2006, the Company entered into a contract with JPMorgan Ventures Energy Corporation to purchase 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. JPMorgan Ventures Energy Corporation's obligations under the contract are subject to a guarantee of $25 million from JPMorgan Chase & Co., its parent company. Following expiration of the Morgan Stanley Contract and after commencement of the contract with JPMorgan Ventures Energy Corporation, the Company will have approximately 100,000 mWh of remaining off-peak load exposed to market prices during the period 2007 - 2010. 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 open position represents approximately 5 percent of Company load, and because it is off-peak is subject to less than average pricing volatility. The replacement power costs reflected in the JPMorgan agreement and the forecasted costs of the Company's remaining open position are substantially included in the Company's 2006 Retail Rate Filing.

Defined Benefit Plans

The Company's defined benefit plan assets are primarily made up of public equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased defined benefit plan costs in future periods.

The Company's funding policy is to make voluntary contributions to its defined benefit plans before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company expects to contribute approximately $2.0 million to defined benefits plans during 2006.

Power Supply Derivatives

The Morgan Stanley Contract is used to hedge our power supply costs against increases in fossil fuel prices. The Morgan Stanley Contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133"). Management has estimated the fair value of the future net benefit of this agreement at March 31, 2006 to be approximately $8.2 million.

The Company has one other less significant derivative position, a forward sale settling in the month of April 2006 made to capture forward energy prices that were high by historical standards.

We currently have an agreement that grants Hydro Quebec an option (the "9701 agreement") to call power at prices that are expected to be below estimated future market rates. This agreement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for the 9701 agreement at March 31, 2006 is approximately $28.8 million. Hydro Quebec has exercised its 9701 option for delivery during the first quarter of 2006. Future 9701 obligations to Hydro Quebec are not presently covered by existing energy supplies.

The table below presents the Company's market risk of the Morgan Stanley Contract, the forward sale contract and the 9701 agreement derivatives, estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in wholesale energy prices, which nets to approximately $3.1 million. Actual results may differ materially from the table illustration. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are deferred.

Commodity Price Risk	At March 31, 2006	
	Fair Value(Cost)	Market Risk
	(in thousands)	
Morgan Stanley Contract	$ 8,158	$ 911
9701 agreement	(28,774)	(4,056)
Forward sale contracts	249	58
	$ (20,367)	$ (3,087)

New Accounting Standards

See Part I-Item 1, Note 5, "New Accounting Standards" for information on the adoption of new accounting standards and the impact, if any, on the Company's financial position and operating results.

ITEM 4. CONTROLS AND PROCEDURES

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, the Company carried out an evaluation, with the participation of the Company's management, including the Company's President and Chief Executive Officer, and Chief Financial Officer and Treasurer, of the effectiveness of the Company's disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, the Company's President and Chief Executive Officer, and Chief Financial Officer and Treasurer, concluded that the Company's disclosure controls and procedures are effective as of the end of the period covered by this report.

There has been no change in our internal control over financial reporting during the quarter ended March 31, 2006, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See Note 3 of Notes to Consolidated Financial Statements under Item 1 - Financial Statements.

Item 1A. RISK FACTORS

While we attempt to identify, manage and mitigate risks and uncertainties associated with our business to the extent practical under the circumstances, some level of risk and uncertainty will always be present. Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005 describes some of the risks and uncertainties associated with our business. These risks and uncertainties have the potential to materially affect our results of operations and our financial condition. We do not believe that there have been any material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2005.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

NONE.

Item 3. DEFAULTS UPON SENIOR SECURITIES

NONE.

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

NONE.

Item 5. OTHER INFORMATION

NONE.

Item 6.EXHIBITS

Exhibit 31.1, Certification by Christopher L. Dutton, President and Chief Executive Officer of Green Mountain Power Corporation, pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2, Certification by Dawn D. Bugbee, Vice President Chief Financial Officer and Principal Accounting Officer of Green Mountain Power Corporation, pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.1, Certification by Christopher L. Dutton, President and Chief Executive Officer of Green Mountain Power Corporation, and Dawn D. Bugbee, Vice President, Chief Financial Officer and Principal Accounting Officer of Green Mountain Power Corporation, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

GREEN MOUNTAIN POWER CORPORATION
SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GREEN MOUNTAIN POWER CORPORATION	
By: /s/ Christopher L. Dutton	May 9, 2006
Christopher L. Dutton	Date
President and	
Chief Executive Officer	
By: /s/ Dawn D. Bugbee	May 9, 2006
Dawn D. Bugbee	Date
Vice President, Chief Financial Officer	
and Principal Accounting Officer	