GREEN MOUNTAIN POWER CORP
Form 10-Q
August 12, 2003

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2003

OR

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	03-0127430
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(I.R.S. EMPLOYER IDENTIFICATION NO.)

163 ACORN LANE COLCHESTER, VT	05446
ADDRESS OF PRINCIPAL EXECUTIVE OFFICES	(ZIP CODE)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE (802) 864-5731

INDICATE BY CHECK MARK WHETHER THE REGISTRANT (1) HAS FILED ALL REPORTS REQUIRED TO BE FILED BY SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934 DURING THE PRECEDING 12 MONTHS (OR FOR SUCH SHORTER PERIOD THAT THE REGISTRANT WAS REQUIRED TO FILE SUCH REPORTS), AND (2) HAS BEEN SUBJECT TO SUCH FILING REQUIREMENTS FOR THE PAST 90 DAYS. YES X NO

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

CLASS - COMMON STOCK	OUTSTANDING AT JULY 31, 2003
$3.33 1/3 PAR VALUE	4,976,557

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," "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 relevant 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.

PART I FINANCIAL INFORMATION

GREEN MOUNTAIN POWER CORPORATION
INDEX TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES
AT AND FOR THE THREE AND SIX MONTHS ENDED JUNE 30,
2003 AND 2002

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED COMPARATIVE INCOME STATEMENTS

	UNAUDITED			
	THREE MONTHS ENDED JUNE 30		SIX MONTHS JUNE 30	
	2003	2002	2003	2
(in thousands, except per share data)				
OPERATING REVENUES	$64,455	$65,135	$137,400	$13
OPERATING EXPENSES				
Power Supply				
Vermont Yankee Nuclear Power Corporation.	9,747	8,191	19,285	1
Company-owned generation.	1,112	617	4,484	
Purchases from others	36,101	37,588	72,377	7
Other operating.	3,787	3,547	8,187	
Transmission	3,490	4,002	7,547	
Maintenance.	1,912	2,059	4,028	
Depreciation and amortization.	3,403	3,408	6,951	
Taxes other than income.	1,940	1,934	3,959	
Income taxes	538	975	2,926	

Total operating expenses	62,030	62,321	129,744	12
OPERATING INCOME	2,425	2,814	7,656	
OTHER INCOME				
Equity in earnings of affiliates and non-utility operations	414	535	826	
Allowance for equity funds used during construction	90	49	176	
Other income (deductions), net	(23)	15	113	
TOTAL OTHER INCOME	481	599	1,115	
INCOME BEFORE INTEREST CHARGES	2,906	3,413	8,771	
INTEREST CHARGES				
Long-term debt	1,755	1,254	3,516	
Other interest	90	295	166	
Allowance for borrowed funds used during construction	(60)	(22)	(118)	
TOTAL INTEREST CHARGES	1,785	1,527	3,564	
INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS	1,121	1,886	5,207	
Dividends on preferred stock	1	11	2	
Income from continuing operations	1,120	1,875	5,205	
Income (loss) from discontinued segment, including provisions for operating losses during phaseout period	(8)	-	(21)	
NET INCOME APPLICABLE TO COMMON STOCK	$ 1,112	$ 1,875	$ 5,184	$

UNAUDITED

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2003	2002	2003	2002
Net income	$1,112	$1,875	$5,184	$5,231
Comprehensive income	-	-	-	-
Other comprehensive income, net of tax	$1,112	$1,875	$5,184	$5,231
Basic earnings per share	$ 0.22	$ 0.33	$ 1.04	$ 0.92
Diluted earnings per share	0.22	0.32	1.01	0.89
Cash dividends declared per share	$ 0.19	$ 0.14	$ 0.38	$ 0.28
Weighted average common shares outstanding-basic	4,969	5,711	4,964	5,701
Weighted average common shares outstanding-diluted	5,129	5,877	5,125	5,866

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Unaudited For the Six Months Ended June 30 2003	2002
OPERATING ACTIVITIES:	(in thousands)	
Net income before preferred dividends	$ 5,186	$ 5,326
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	6,951	6,939
Dividends from associated companies less equity income	(100)	97
Allowance for funds used during construction	(293)	(176)
Amortization of deferred purchased power costs	2,316	3,611
Deferred income taxes	1,049	988
Deferred purchased power costs	(86)	(2,075)
Rate levelization liability	238	(4,309)
Conservation deferrals, net	(207)	(176)
Changes in:		
Accounts receivable and accrued utility revenues	1,886	2,058
Prepayments, fuel and other current assets	(32)	1,843
Accounts payable and other current liabilities	(3,406)	(3,043)
Accrued income taxes payable and receivable	481	1,359
Other	325	152
Net cash provided by operating activities	14,308	12,594
INVESTING ACTIVITIES:		
Construction expenditures	(7,718)	(8,638)
Environmental expenditures, net	(2,113)	(624)
Invesment in Associated Companies	(108)	-
Investment in nonutility property	(73)	(100)
Net cash used in investing activities	(10,012)	(9,362)
FINANCING ACTIVITIES:		
Payments to acquire treasury stock	(3)	-
Repurchase of preferred stock	-	(12,325)
Issuance of common stock	192	472
Reduction in long-term debt	-	(5,100)
Short-term debt, net	(2,500)	10,400
Cash dividends	(1,888)	(1,664)
Net cash used in financing activities	(4,199)	(8,217)
Net increase (decrease) in cash and cash equivalents	98	(4,985)
Cash and cash equivalents at beginning of period	1,909	5,006
Cash and cash equivalents at end of period	$ 2,007	$ 21
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid year-to-date for: Interest (net of amounts capitalized)	$ 3,542	$ 3,053
Income taxes	1,758	2,349

SUPPLEMENTAL DISCLOSURE OF NON-CASH INFORMATION:
A capital lease obligation of $181 was incurred when the Company entered into a lease for new office furniture during February 2003.

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

GREEN MOUNTAIN POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

	UNAUDITED JUNE 30	DECEMBER 31	
	2003	2002	20
	(in thousands)		
ASSETS			
UTILITY PLANT			
Utility plant, at original cost	$ 314,275	$306,127	$311
Less accumulated depreciation	128,397	122,950	122
Net utility plant	185,878	183,177	189
Property under capital lease	5,522	5,959	5
Construction work in progress	13,980	10,530	8
Total utility plant, net	205,380	199,666	203
OTHER INVESTMENTS			
Associated companies, at equity	14,329	14,019	14
Other investments	7,369	7,108	7
Total other investments	21,698	21,127	21
CURRENT ASSETS			
Cash and cash equivalents	2,007	21	1
Accounts receivable, less allowance for doubtful accounts of $547, $613 and $547	15,946	15,902	17
Accrued utility revenues	6,038	5,015	6
Fuel, materials and supplies, at average cost	4,188	3,885	3
Prepayments	1,140	413	1
Other	356	363	
Total current assets	29,675	25,599	31
DEFERRED CHARGES			
Demand side management programs	6,471	6,687	6
Purchased power costs	114	1,995	2
Pine Street Barge Canal	13,019	12,425	13
Power supply derivative deferral	21,160	33,694	18
Other	10,546	14,612	11
Total deferred charges	51,310	69,413	51
NON-UTILITY			
Other current assets	8	8	
Property and equipment	249	250	
Other assets	663	775	
Total non-utility assets	920	1,033	

TOTAL ASSETS	$ 308,983	$316,838	$309

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	UNAUDITED JUNE 30 2003	2002	DECEMBER 31 2002
(in thousands except share data)			
CAPITALIZATION AND LIABILITIES			
CAPITALIZATION			
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,803,596 ,5,716,975 and 5,782,496)	$ 19,345	$ 19,110	$ 19,276
Additional paid-in capital.	75,469	74,948	75,347
Retained earnings	19,469	11,683	16,171
Accumulated other comprehensive income.	(2,374)	-	(2,374)
Treasury stock, at cost (827,639 and 15,856 shares)	(16,701)	(378)	(16,698)
Total common stock equity	95,208	105,363	91,722
Redeemable cumulative preferred stock	55	85	55
Long-term debt, less current maturities	93,000	71,000	93,000
Total capitalization.	188,263	176,448	184,777
CAPITAL LEASE OBLIGATION.	5,496	5,959	5,287
CURRENT LIABILITIES			
Current maturities of preferred stock	30	150	30
Current maturities of long-term debt.	8,000	8,000	8,000
Short-term debt	-	10,400	2,500
Accounts payable, trade and accrued liabilities . .	4,358	6,410	7,431
Accounts payable to associated companies.	8,535	6,825	8,940
Rate levelization liability	4,329	4,218	4,091
Accrued income taxes.	5,065	933	4,583
Customer deposits	840	838	898
Interest accrued.	1,182	1,145	1,081
Other	965	1,081	937
Total current liabilities	33,304	40,000	38,491
DEFERRED CREDITS			
Power supply derivative liability	21,160	33,694	18,405
Accumulated deferred income taxes	27,662	24,888	26,471
Unamortized investment tax credits.	2,989	3,272	3,130
Pine Street Barge Canal cleanup liability	6,720	9,436	8,833
Other	21,562	20,787	21,767
Total deferred credits.	80,093	92,077	78,606

COMMITMENTS AND CONTINGENCIES			
NON-UTILITY			
Net liabilities of discontinued segment	1,827	2,354	1,941
Total non-utility liabilities	1,827	2,354	1,941
TOTAL CAPITALIZATION AND LIABILITIES.	$308,983	$316,838	$309,102

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

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS In thousands	UNAUDITED THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2003	2002	2003	2002
Balance - beginning of period.	$19,300	$10,644	$16,171	$ 8,070
Net Income	1,113	1,886	5,186	5,326
Other		(50)		(50)
Cash Dividends-redeemable cumulative preferred stock	(1)	(11)	(2)	(95)
Cash Dividends-common stock.	(943)	(786)	(1,886)	(1,568)
Balance - end of period.	$19,469	$11,683	$19,469	$11,683

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

GREEN MOUNTAIN POWER CORPORATION
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2003

PART I-ITEM 1
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 period 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 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 2002 filed on Form 10-K, are adequate to make the information presented not misleading.

Management believes the most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate, the manner in which we account for certain power supply arrangements that qualify as derivatives, and the defined benefit plan assumptions used to determine plan liabilities for our defined benefit retirement plans. These accounting policies, among others, affect the Company's more significant judgments and estimates used in the preparation of its consolidated financial statements.

The Vermont Public Service Board ("VPSB"), the regulatory commission in Vermont, sets the rates we charge our customers for their electricity. In periods prior to April 2001, we charged our customers higher rates for billing cycles in December through March and lower rates for the remaining months. These were called seasonally differentiated rates. Seasonal rates were eliminated in April 2001, and generated approximately $8.5 million of revenues deferred in 2001, of which $4.4 million was recognized during 2002. The remaining $4.1 million will be used to offset increased costs or write off regulatory assets during 2003 or 2004.

The Company operates under a rate cap which requires the deferral of revenue in periods where the Company earns more than its allowed rate of return. Conversely, previously deferred revenue is recognized in periods when the Company is not achieving its allowed return. During the three months ended June 2002, approximately $2.1 million of previously deferred revenue was recognized in order for the Company to achieve its allowed rate of return. Due to an improvement in operating results for the quarter ended June 30, 2003, compared with the same period in 2002, the Company deferred approximately $271,000 of revenue based on the expectation that it will exceed its return on equity. For the six months ended June 30, 2003 the Company did not recognize nor defer any revenues, compared with $4.3 million of previously deferred revenue recognized during the six months ended June 30, 2002.

Certain line items on the prior year's financial statements have been reclassified for consistent presentation with the current year. 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 those estimates.

The Company applies Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations in accounting for its stock option plan and has adopted the disclosure-only provisions of SFAS 123, "Accounting for Stock-Based Compensation" as amended by SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - and amendment of SFAS 123". The following table illustrates the effect on net income and earnings per share as if the fair value method had been applied to all outstanding and unvested awards in each period. The fair value of options at date of grant was estimated using the Black-Scholes option-pricing model. Had the Company expensed stock-based compensation under SFAS 123, the Company's diluted earnings would have been reduced by $0.01 and $0.01 per share for the three and six months ended June 30, 2003, respectively.

Pro-forma net income	Three months ended June 30		Six months ended June 30	
	2003	2002	2003	2002
In thousands, except per share amounts				
Net income reported.	$1,112	$1,875	$5,184	$5,231
Pro-forma net income	1,072	1,830	5,103	5,140
Net income per share				
As reported-basic.	0.22	0.33	1.04	0.92
Pro-forma basic.	0.22	0.32	1.03	0.90
As reported-diluted.	0.22	0.32	1.01	0.89
Pro-forma diluted.	0.21	0.31	1.00	0.88

UNREGULATED OPERATIONS

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

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 YANKEE NUCLEAR POWER CORPORATION ("VY" OR "VERMONT YANKEE")
PERCENT OWNERSHIP: 19.0% COMMON

	Three months ended June 30		Six months ended June 30	
	2003	2002	2003	2002
(in thousands)				
Gross Revenue.	$49,014	$46,764	$96,982	$85,495
Net Income Applicable. to Common Stock	722	1,462	$ 1,407	2,949
Equity in Net Income .	140	258	267	571

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

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

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

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

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

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

The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the Entergy plant. The Company expects its share of the Vermont Yankee sale proceeds, currently estimated at between $7.0 and $8.0 million, to be distributed in the latter part of 2003.

The sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervener parties to the VPSB approval proceeding appealed the VPSB approval to the

Vermont Supreme Court. The Vermont Supreme Court affirmed the VPSB approval in July 2003.

VERMONT ELECTRIC POWER COMPANY, INC. ("VELCO")
Percent ownership: 28.41% common
30.0% preferred

VELCO is a corporation engaged in the transmission of electric power within the State of Vermont. VELCO has entered into transmission agreements with the State of Vermont and various electric utilities, including the Company, and under these agreements, VELCO bills all costs, including interest on debt and a fixed return on equity, to the State and others using VELCO's transmission system.

	Three months ended June 30		Six months ended June 30	
	2003	2002	2003	2002
(in thousands)				
Gross Revenue	$5,635	$5,312	$11,270	$11,796
Net Income.	349	318	622	513
Equity in Net Income.	91	92	197	169

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 comply with these requirements and that there are no outstanding material complaints about the Company's compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site.

PINE STREET BARGE CANAL SITE

The Federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), commonly known as the "Superfund" law, generally imposes strict, joint and several liability, regardless of fault, for remediation of property contaminated with hazardous substances. We are one of several potentially responsible parties ("PRPs") for cleanup of the Pine Street Barge Canal ("Pine Street") site in Burlington, Vermont, where coal tar and other industrial materials were deposited.

In September 1999, we negotiated a final settlement with the United States, the State of Vermont (the "State"), and other parties to a Consent Decree that covers claims with respect to the site and implementation of the selected site cleanup remedy. In November 1999, the Consent Decree was filed in the federal district court. The Consent Decree addresses claims by the Environmental Protection Agency (the "EPA") for past Pine Street site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site.

As of June 30, 2003, our total expenditures related to the Pine Street site since 1982 were approximately $29.5 million. This includes amounts not recovered in rates, amounts recovered in rates, and amounts for which rate recovery has been sought but which are presently waiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals of a more expensive remedy at the site, litigation and related costs necessary to obtain settlements with insurers and other PRPs to provide amounts required to fund the clean up ("remediation costs"), and to address liability claims at the site. A smaller amount of past expenditures was for site-related response costs, including costs incurred pursuant to EPA and State orders that resulted in funding response activities at the site, and to reimbursing the EPA and the State for oversight and related response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be $13.0 million through 2033. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We also have recorded an offsetting regulatory asset, and we believe that it is probable that we will receive future revenues to recover these costs.

Through rate cases filed in 1991, 1993, 1994, and 1995, we sought and received recovery for ongoing expenses associated with the Pine Street site. While reserving the right to argue in the future about the appropriateness of full rate recovery of the site-related costs, the Company and the Vermont Department of Public Service (the "Department"), and as applicable, other parties, reached agreements in these cases that the full amount of the site-related costs reflected in those rate cases should be recovered in rates.

We proposed in our rate filing made on June 16, 1997 recovery of an additional $3.0 million in such expenditures. In an Order in that case released March 2, 1998, the VPSB suspended the amortization of expenditures associated with the Pine Street site pending further proceedings. Although it did not eliminate the rate base deferral of these expenditures, or make any specific order in this regard, the VPSB indicated that it was inclined to agree with other parties in the case that the ultimate costs associated with the Pine Street site, taking into account recoveries from insurance carriers and other PRPs, should be shared between customers and shareholders of the Company. In response to our Motion for Reconsideration, the VPSB on June 8, 1998 stated its intent was "to reserve for a future docket issues pertaining to the sharing of remediation-related costs between the Company and its customers".

On July 13, 2003, the Company and the Department entered into a Memorandum of Understanding relating primarily to the Company's rates and allowed rate of return through 2006. This Memorandum of Understanding provides for recovery of Pine Street costs over a twenty-year period without a return. This Memorandum of Understanding has not yet been approved by the VPSB. See the discussion under Retail Rate Case below for further details.

RETAIL RATE CASE

On January 23, 2001, the VPSB approved a final settlement of the Company's 1998 rate case. The VPSB Order approving the settlement contained the following provisions:

The Company received a rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases became permanent;

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

The Company agreed not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for additional rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;

The Company agreed to write off in 2000 approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaced short-term credit facilities with long-term debt or equity financing;

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

The Company agreed to consult extensively with the Department regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making;

The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in a 1997 rate case; and

The Company agreed to an earnings limitation for its electric operations in an amount equal to its allowed rate of return of 11.25 percent, with amounts earned over the limit being used to write off regulatory assets.

The Company and customers shall share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share, adjusted for inflation; and

The Company's further investment in non-utility operations is restricted.

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

On October 10, 2002, the VPSB issued an order approving the Company's request to issue long-term debt, with the proceeds to be used to repay existing intermediate term indebtedness and short-term debt outstanding under the Company's revolving credit facility. The Company used proceeds of a $42 million long-term debt issue in December 2002 to repurchase equity and to replace all short-term borrowings, satisfying the conditions in the VPSB final settlement order and permitting the Company to raise its dividend.

The VPSB, in its order approving VY's sale of its nuclear power plant to Entergy, ordered the Company and Central Vermont Public Service each to file on or before April 15, 2003, a cost-of-service study based on actual 2002 data, to enable the VPSB to determine whether an adjustment to rates is justified in 2003 or 2004. The Company filed its study on April 15, 2003.

On July 11, 2003, after the Department completed its review of the Company's cost-of-service filing, the Company and the Department entered into a Memorandum of Understanding (the "Memorandum") regarding the Company's rates and allowed return on equity through the end of 2006. The Memorandum is subject to approval by the VPSB, and provides, among other things, the following:

Rate Stability: The Company's rates will remain unchanged until January 1, 2005, when they will increase by 1.9 percent, and an additional rate increase of 0.9 percent will be effective January 1, 2006, subject to the requirement that the Company file a cost of service filing with the Department and the VPSB 60 days prior to each rate increase that supports such increase. In addition, the Memorandum permits the Company to carry forward into 2004 any unused deferred revenue originally allowed in the Company's January 2001 rate order.

Earnings Cap: The Memorandum provides that the Company will reduce its current 11.25 percent allowed return on equity to 10.50 percent for 2003, 2004, 2005 and 2006. The Memorandum further provides that the Company may carry forward any remaining deferred revenue at December 31, 2003, through 2004 to offset increased costs or reduce regulatory assets. If the Company earns in excess of its earning cap, then any 2003 or 2004 excess earnings shall be applied to reduce regulatory assets. Excess earnings in 2005 or 2006 shall be refunded to customers as a credit on customer bills or applied to reduce regulatory assets as the Department directs.

Redesign of Rates: Within 60 days of the Board's approval of the Memorandum, the Company shall file with the Board a fully allocated cost of service study and rate redesign, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. Such a rate redesign will be subject to VPSB approval.

Alternative Regulation Plan: The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted by the Vermont legislature in 2003, within 120 days after Board approval of the Memorandum. If the Company and the Department agree on such a plan, and it is approved by the VPSB, the plan would supersede the terms of the Memorandum.

Amortization of Regulatory Assets: Under the Memorandum, amortization (recovery) of certain regulatory assets, including Pine Street Barge Canal environmental site costs, and past demand side management program costs will begin January 2005 and will be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

POWER CONTRACT COMMITMENTS

Under an arrangement established on December 5, 1997 ("9701"), Hydro-Quebec paid $8.0 million to the Company. In return for this payment, we provided Hydro-Quebec options for the purchase of power. Commencing April 1, 1998 and effective through 2015, the term of a previous contract with Hydro-Quebec (the "1987 Contract"), Hydro-Quebec may purchase up to 52,500 MWh ("option A") on an annual basis, at the 1987 Contract energy prices, which are substantially below current market prices. The cumulative amount of energy that may be purchased under option A shall not exceed 950,000 MWh. Over the same period, Hydro-Quebec may exercise an option to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy prices. Under option B, Hydro-Quebec may purchase no more than 200,000 MWh in any year.

During the first six months of 2003, $2.5 million in power supply expense was recognized to reflect the cost of option A and B, compared with $1.5 million during the first half of 2002 for option A only. Hydro-Quebec had previously agreed not to call option B during the contract year ended October 31, 2002. At June 30, 2003, the cumulative amount of power purchased by Hydro-Quebec under option B is approximately 458,000 MWh.

Hydro-Quebec's option to curtail annual energy deliveries pursuant to a July 1994 Agreement can be exercised in addition to these purchase options if documented drought conditions exist. The exercise of this curtailment option is limited to five times, requiring notice four months in advance of any contract year, and cannot reduce deliveries by more than approximately 13 percent. The Company may defer the curtailment by one year. Hydro-Quebec also has the option to reduce the annual load factor from 75 percent to 65 percent under the 1987 Contract a total of three times over the life of the contract. Pursuant to the 1987 Contract, Hydro-Quebec reduced its load factor to 65 percent in 2003 and has notified the Company of its intention to reduce the load factor to 65 percent in 2004. The Company estimates that the net cost of Hydro-Quebec's exercise of its load factor reduction option will increase power supply expense during 2003 by approximately $0.4 million.

It is possible our estimate of future power supply costs could differ materially from actual results.

4. SEGMENTS AND RELATED INFORMATION

The Company's electric utility operation is its only operating segment. The electric utility is engaged in the distribution and sale of electrical energy in the State of Vermont and also reports the results of its wholly owned unregulated subsidiaries (GMPG, GMRI, GMPIC and GMP Real Estate) and the rental water heater program as a separate line item in the Other Income section in the

Consolidated Statement of Income.

NWR is an unregulated business that invested in energy generation, energy efficiency and wastewater treatment projects. As of June 30, 2003, most of NWR's net assets and liabilities have been sold or otherwise disposed. The remaining net liability reflects expected warranty obligations, net of equity investments in a wind farm and wastewater treatment projects.

5. DERIVATIVE INSTRUMENTS AND RISK MANAGEMENT

The Company records the annual cost of power obtained under long-term contracts as operating expenses. The Company meets the majority of its customer demand through a series of long-term physical and financial contracts. There are occasions when we may experience a short position for electricity needed to supply customers. During those periods, electricity is purchased at market prices.

SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS 133, as amended by SFAS 137, was effective for the Company beginning 2001.

One objective of the Company's risk management program is to stabilize cash flow and earnings by minimizing power supply risks. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and transmission congestion rights contracts with counter-parties that have at least investment grade ratings. These transactions are used to mitigate the risk of fossil fuel and spot market electricity price increases. The Company's risk management policy specifies risk measures and authorization limits for transactions. Derivative financial instruments held by the Company are used as hedges or for cost control and not for trading.

On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings or other comprehensive income effects relating to future periods caused by application of SFAS 133. At June 30, 2003, the Company had a liability reflecting the net negative fair value of the two derivatives described below, as well as a corresponding regulatory asset of approximately $21.2 million. The Company believes that the regulatory asset, determined using the Black's or Black-Scholes option valuation method, is probable of recovery in future rates. The regulatory liability is based on current estimates of future market prices that are likely to change by material amounts.

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

The Company has a contract with Morgan Stanley Capital Group, Inc. ("MS") used to hedge against increases in fossil fuel prices. MS purchases the majority of the Company's power supply resources at index (fossil fuel resources) or specified (i.e., contracted resources) prices and then sells to us at a fixed rate to serve pre-established load requirements. This contract allows management to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The MS contract is a derivative under SFAS 133 and is effective through December 31, 2006. Management's estimate of the fair value of the future net benefit of this contract at June 30, 2003 is approximately $6.6 million.

As described under "Power Contract Commitments", the 9701 arrangement grants Hydro-Quebec an option to call power at prices below current and estimated future market rates. This arrangement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for this arrangement at June 30, 2003 is approximately $27.7 million. We use futures contracts to hedge the 9701 call option.

6. NEW ACCOUNTING STANDARDS

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), effective for fiscal years beginning after June 15, 2002, which provides guidance on accounting for nuclear plant decommissioning and other asset retirement costs. SFAS 143 prescribes fair value accounting for asset retirement liabilities, including nuclear decommissioning obligations, and requires recognition of such liabilities at the time incurred. The Company has no legal retirement obligations associated with asset retirement obligations. Other removal costs related to utility plant, estimated at approximately $20.4 million, are included in accumulated depreciation. The Company adopted SFAS No. 143 on January 1, 2003 as required. There was no cumulative effect of adopting SFAS No. 143.

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" ("SFAS 146"). SFAS 146 specifies accounting and reporting for costs associated with exit or disposal activities. The application of this accounting standard, which is effective for the three months ended June 30, 2003, did not materially impact the Company's financial position or results of operations.

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

In January 2003, the Financial Accounting Standards Board issued Interpretation 46, Consolidation of Variable Interest Entities. This standard will require an enterprise that is the primary beneficiary of a variable interest entity to consolidate that entity. The Interpretation must be applied to any existing interests in variable interest entities beginning in the third quarter of 2003. The Company does not expect to consolidate any existing interest in unconsolidated entities as a result of Interpretation 46.

In April 2003, the FASB issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"("SFAS 149"). SFAS 149 amends Statement 133 for decisions made (1) as part of the Derivatives Implementation Group process that effectively required amendments to Statement 133, (2) in connection with other Board projects dealing with financial instruments, and (3) in connection with implementation issues raised in relation to the application of the definition of a derivative, in particular, the meaning of an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors, the meaning of underlying, and the characteristics of a derivative that contains financing components. Effective for contracts entered into or modified after June 30, 2003, we do not expect this statement to have a material effect on our financial position or results of operations.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"(SFAS 150"). SFAS 150 establishes standards for classifying and measuring financial instruments with characteristics of both liabilities and equity. Effective for financial instruments entered into or modified after May 31, 2003, we do not expect this statement to have a material effect on our financial position or results of operations.

7. COMPUTATION OF EARNINGS PER SHARE

Earnings per share are based on the weighted average number of common and common stock equivalent shares outstanding during each year. The Company established a stock incentive plan for all directors and employees during the year ended December 31, 2000, and options granted are exercisable over vesting schedules of between one and four years.

(in thousands)	Three months ended June 30 2003	Three months ended June 30 2002	Six months ended June 30 2003	Six months ended June 30 2002
Net income before preferred dividends	$1,113	$1,886	$5,186	$5,326
Preferred stock dividend requirement.	1	11	2	95
Net income applicable to common stock	$1,112	$1,875	$5,184	$5,231
Weighted average number of common shares-basic. .	4,969	5,711	4,964	5,701
Dilutive effect of stock options.	159	166	161	165
Anti-dilutive stock options	-	-	-	-
Weighted average number of common shares-diluted.	5,128	5,877	5,125	5,866

GREEN MOUNTAIN POWER CORPORATION
PART I-ITEM 2
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL
CONDITION AND RESULTS OF OPERATIONS
JUNE 30, 2003

In this section, we explain the general financial condition and the results of operations for Green Mountain Power Corporation (the "Company") and its subsidiaries. This 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 year-to-date and what we expect they will be in the future;

Where we expect to get cash for future capital expenditures; and

How all of the above affects our overall financial condition.

Management believes the most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate, the manner in which we account for certain power supply arrangements that qualify as derivatives, and the defined benefit plan assumptions used to determine plan liabilities for our defined benefit retirement plans. These accounting policies, among others, affect the Company's more significant judgments and estimates used in the preparation of its consolidated financial statements.

As you read this section it may be helpful to refer to the consolidated financial statements and notes in Part I-Item 1.
There are statements in this section that contain projections or estimates and are considered to be "forward-looking" as defined by the Securities and Exchange Commission. In these statements, you may find words such as "believes,"

"estimates," "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 materially different from those projected. Some of the reasons the results may be different are listed below and are discussed under "Competition and Restructuring" in this section:

- Regulatory and judicial decisions or legislation;
- Weather;
- Energy supply and demand and pricing;
- Availability, terms, and use of capital;
- General economic and business risk;
- Nuclear and environmental issues;
- Changes in technology; and
- Industry restructuring and cost recovery (including stranded costs).

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

RESULTS OF OPERATIONS

EARNINGS SUMMARY - OVERVIEW

In this section, we discuss our earnings and the principal factors affecting them. We separately discuss earnings for the utility business and for our unregulated businesses.

Total basic earnings per share of Common Stock

	Three months ended June 30		Six months ended June 30	
	2003	2002	2003	2002
Utility business	$0.20	$0.31	$1.00	$0.89
Unregulated businesses .	0.02	0.02	0.04	0.03
Earnings from:				
Continuing operations. .	0.22	0.33	1.04	0.92
Discontinued operations.	-	-	-	-
Basic earnings per share	$0.22	$0.33	$1.04	$0.92

UTILITY BUSINESS

The Company recorded basic earnings per share from utility operations of $0.20 in the quarter ended June 30, 2003, compared with utility earnings of $0.31 per share in the second quarter of 2002. Earnings declined primarily due to a reduction in the amounts of deferred revenues recognized and increased interest expenses, partially offset by a decrease in transmission costs.

Basic earnings per share from utility operations for the six months ended June 30, 2003 were $1.00 compared with basic earnings per share of $0.89 for the same period in 2002. Earnings improved primarily due to increased wholesale and retail sales of electricity that more than offset increased power supply costs, decreased recognition of deferred revenues, and higher interest expense.

UNREGULATED BUSINESSES

Earnings from unregulated businesses, principally from the Company's water heater rental program, included in results from continuing operations for the three and six months ended June 30, 2003 were slightly higher than during the same period in 2002. A financial summary for these businesses follows:

	Three Months Ended June 30 2003	2002	Six Months Ended June 30 2003	2002
	(In thousands)			
Revenue. .	$ 247	$ 253	$ 497	$ 502
Expense. .	117	150	261	316
Net Income	$ 130	$ 103	$ 236	$ 186

OPERATING REVENUES AND MWH SALES

Our revenues from operations, megawatt hour ("MWh") sales and average number of customers for the three and six months ended June 30, 2003 and 2002 are summarized below:

	Three months ended June 30 2003	2002	Six months ended June 30 2003	2002
(dollars in thousands)				
Operating revenues				
Retail.	$ 45,935	$ 48,256	$ 98,372	$ 100,745
Sales for Resale. . .	17,716	16,092	37,641	31,901
Other	804	787	1,387	1,355
Total Operating Revenues.	$ 64,455	$ 65,135	$ 137,400	$ 134,001
MWh Sales-Retail.	450,945	457,128	957,220	955,136
MWh Sales for Resale. . .	534,644	517,937	1,080,562	1,036,224
Total MWh Sales	985,589	975,065	2,037,782	1,991,360

Average Number of Customers

	Three months ended June 30 2003	2002	Six months ended June 30 2003	2002
Residential	74,488	73,730	73,861	73,831
Commercial and Industrial	13,314	13,104	13,194	13,076
Other	65	67	65	65
Total Number of Customers. .	87,867	86,901	87,120	86,972

REVENUES

Total revenues from operations in the second quarter of 2003 decreased $0.7 million or 1.0 percent compared with the same period in 2002, primarily as a result of a decrease of $2.3 million in recognition of deferred revenues, and a decrease of approximately $1.1 million in commercial and industrial revenues, partially offset by a $1.7 million increase in sales for resale, and a $602,000 increase in residential revenues.

Retail operating revenues reflected a $2.3 million decline in the recognition of deferred revenues during the second quarter of 2003, compared with the same quarter of 2002. Revenues were deferred during 2001 in accordance with the settlement of the Company's retail rate case approved by the Vermont Public Service Board (the "VPSB") in January 2001(the "Settlement Order"). The Settlement Order resulted in the elimination of seasonal rates, generating an additional $8.5 million in cash flow in 2001. The Settlement Order provided that recognition of this additional $8.5 million of revenue be deferred and then recognized to offset increased costs during 2001, 2002, or 2003. As of June 30, 2003, the Company has $4.1 million in unused remaining deferred revenues, which will be used to offset increased costs or write off regulatory assets during 2003 or 2004. See Notes-Retail Rate Case for further details.

Total retail MWh sales of electricity in the second quarter of 2003 increased 1.1 percent from the same quarter of 2002, primarily as a result of an increase in residential sales of 7.6 percent, partially offset by a decrease in sales of 5.8 percent to commercial customers. Sales to large industrial customers also declined by 3.2 percent during the same period, reflecting reduced energy consumption under a load shedding program that we manage.

The Company's major industrial customer, International Business Machines ("IBM"), accounted for 17.3% of retail sales revenue in 2002. The Company currently estimates, based on a number of projected variables, the retail rate increase required from all retail customers by a hypothetical shutdown of the IBM facility to be in the range of five to eight percent, inclusive of projected related declines in sales to residential and commercial customers.

We sell wholesale electricity to others for resale. Our revenue from wholesale MWh sales of electricity increased approximately $1.6 million or 10.1 percent in the second quarter of 2003 compared with the same period in 2002. The increase was due primarily to increased market energy prices.

Retail operating revenues reflected a $4.3 million decline in the recognition of deferred revenues during the first six months of 2003, compared with the same period of 2002, partially offset by an increase of $1.9 million or 2.0 percent in residential revenues during the same comparative periods. Strong operating results during the first half of the year reduce the likelihood that deferred revenue recognition will be needed to achieve the allowed return on equity of 10.5 percent in 2003.

Total retail MWh sales of electricity in the first half of 2003 increased 0.5 percent from the same quarter of 2002, primarily as a result of increased residential sales of 7.1 percent, a decrease in commercial sales of 0.6 percent and a decline in industrial sales of 4.9 percent. The decrease in industrial sales arose primarily from reduced snowmaking. These sales have an immaterial impact on operating results because snowmaking sales are subject to a dispatchable rate tariff arrangement that significantly reduces the Company's margin on such sales.

Wholesale revenues increased $5.7 million or 18.0 percent during the first six months of 2003, compared with the same period in 2002, as a result of rescheduled power supply deliveries and higher market prices. Wholesale revenues typically have an insignificant impact on earnings because market wholesale prices usually approximate our marginal costs for energy, but the first quarter was an exception. One of the Company's principal energy suppliers reduces energy deliveries in the event of system limitations. These delivery deficiencies are typically scheduled at a later time by the Company. During the first quarter of 2003, the Company scheduled approximately 35,000 MWh of energy from this supplier to make up for delivery deficiencies in earlier periods, and sold that energy on the market at unusually high market energy prices. Market energy prices were higher than normal in the first quarter as a result of the Venezuelan oil strike, colder than normal temperatures across the U.S and the threat of war.

OPERATING EXPENSES

POWER SUPPLY EXPENSES

Power supply expenses increased $565,000 or 1.2 percent in the second quarter of 2003 compared with the same period in 2002, as a result of increased wholesale sales of electricity that were in part offset by a $1.8 million decline in costs under the Company's power supply contract with MS.

Power supply expenses at Vermont Yankee increased $1.6 million or 19.0 percent during the second quarter of 2003 compared with the same period of 2002, primarily due to an increase in energy provided under the Power Purchase Agreement between VY and Entergy (the "PPA"). An outage in the second quarter of 2002 reduced energy provided from the Vermont Yankee nuclear power plant. The sale of the VY generating plant is discussed under Part I, Item 1, Note 2, "Investment in Associated Companies".

Company-owned generation expenses increased $495,000 or 80.3 percent in the second quarter of 2003 compared with the same period in 2002, primarily due to increased fuel costs.

The cost of power that we purchased from other companies decreased $1.5 million or 4.0 percent in the second quarter of 2003 compared with the same period in 2002, primarily due to a $1.8 million decrease in cost of power purchased from MS, that was partially offset by increased sales of electricity and increased expenses under the 9701 arrangement with Hydro-Quebec, pursuant to which Hydro-Quebec has the right to purchase electricity from the Company at rates below current market prices. See the discussion under Part I, Item 1, Note 3 "Commitments and Contingencies-Power Contract Commitments" for more detail regarding the 9701 arrangement, and Part I, Item 1, Note 5, "Derivative Instruments and Risk Management" for further information regarding the MS contract.

The 9701 arrangement allows Hydro-Quebec to exercise an option to purchase power from the Company at energy prices based on a 1987 contract, and below current market prices. During the second quarter of 2003, $1.1 million in power supply expense was recognized to reflect the costs of option A and B. During the second quarter of 2002, $0.8 million in power supply expense was recognized to reflect the cost of option A. Hydro-Quebec had previously agreed not to call option B during the 2002 contract year. The cumulative amount of power purchased or called to date by Hydro-Quebec under option B is approximately 513,000 MWh out of a total of 600,000 MWh which may be called over the life of the arrangement. Hydro-Quebec has exercised its option to call approximately 107,000 MWh under options A and B for July and August 2003. The Company previously purchased energy in anticipation of Hydro-Quebec's call.

Both the 9701 arrangement and any related forward purchase contracts are considered derivative instruments as defined by SFAS 133. On April 11, 2001, the VPSB issued an accounting order that allows the Company to defer recognition of any earnings or other comprehensive income effect relating to future periods caused by application of SFAS 133, and as a result, we do not anticipate SFAS 133 to cause earnings volatility. At June 30, 2003, the Company had a regulatory asset of approximately $21.2 million related to derivatives that the Company believes is probable of recovery. The regulatory asset is based on current estimates of future market prices that are likely to change by material amounts.

Power supply expenses increased $2.6 million or 2.8 percent in the first half of 2003 compared with the same period in 2002, as a result of increased wholesale and retail sales of electricity that were in part offset by a $4.2 million decline in costs under the Company's power supply contract with MS.

Power supply expenses at Vermont Yankee increased $3.0 million or 18.6 percent during the first half of 2003 compared with the same period of 2002, primarily due to an increase in energy provided under the Power Purchase Agreement between VY and Entergy. The sale of the VY generating plant is discussed under Part I, Item 1, Note 2, "Investment in Associated Companies".

Company-owned generation expenses increased $2.9 million or 184 percent in the first half of 2003 compared with the same period in 2002, primarily due to increased output and fuel costs at the Stony Brook generating facility in which we have an 8.8 percent joint ownership interest, and increases in fuel costs used to operate our other peak generation facilities.

The cost of power that we purchased from other companies decreased $3.4 million or 4.4 percent in the first half of 2003 compared with the same period in 2002, primarily due to a $4.2 million decrease in the cost of power purchased from MS, that was partially offset by increased sales of electricity and increased expenses under the 9701 arrangement with Hydro-Quebec.

OTHER OPERATING EXPENSES

Other operating expenses increased $240,000 or 6.8 percent in the second quarter of 2003 compared with the same period in 2002, as a result of increases in employee benefit plan and consulting costs. Other operating expenses increased $1.1 million or 16.1 percent in the first half of 2003 compared with the same period in 2002 for the same reasons.

TRANSMISSION EXPENSES

Transmission expenses decreased by approximately $512,000 or 12.8 percent for the three months ended June 30, 2003 compared with the same period in 2002, due to a reduction in the amount of pool transmission expense allocated from the rest of New England as a result of changes in cost allocation methods used by ISO New England.

Transmission expenses decreased by approximately $425,000 or 5.3 percent for the six months ended June 30, 2003 compared with the same period in 2002, for the same reasons.

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

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

Under SMD, the zone experiencing the voltage support problems will pay for costs of local generation used to maintain voltage support for reliability. Previously, these costs would have been allocated throughout New England. VELCO owns certain transmission equipment on a primary transmission line ("PV20 line") supporting northwestern Vermont. This equipment requires repair and will likely be unavailable until next summer. We are unable to estimate whether, or to what degree, VELCO will need to utilize additional generation to replace voltage support previously provided by the PV20 line. If additional generation were required, our share of these costs would be material.

VELCO has proposed a project to substantially upgrade Vermont's transmission system (the "Northwest Reliability Project"), principally to support reliability and eliminate transmission constraints in northwestern Vermont, including most of the Company's service territory. The proposed Northwest Reliability Project must be approved by the VPSB. If approved, the project is estimated to cost approximately $128 million and is expected to be in service by December 2007. Under current NEPOOL rules, qualifying large transmission project costs are shared among all New England utilities as "pooled transmission facilities" ("PTF"), with Vermont utilities responsible for approximately five percent of such regionalized costs. NEPOOL has approved the principal cost components of the Northwest Reliability Project for inclusion as PTF. ISO New England is in the process of developing a proposal to FERC to comply with the SMD NOPR, which will include a proposal for future treatment of transmission investments. ISO New England has issued a preliminary recommendation that maintains the principle of sharing costs of large transmission investments throughout the New England region. ISO New England's recommendation is not yet final and will be subject to approval by FERC.

MAINTENANCE EXPENSES

Maintenance expenses decreased $147,000 or 7.2 percent for the three months ended June 30, 2003 compared with the same period in 2002, primarily due to a decrease in scheduled maintenance at peak generation facilities.

Maintenance expenses decreased $247,000 or 5.8 percent for the six months ended June 30, 2003 compared with the same period in 2002, for the same reasons.

DEPRECIATION AND AMORTIZATION EXPENSES

Depreciation and amortization expenses were essentially unchanged during the second quarter and first half of 2003 compared with the same periods in 2002.

TAXES OTHER THAN INCOME TAXES

Other tax expense for the second quarter and first half of 2003 was essentially unchanged compared with the same periods in 2002.

INCOME TAXES

Income taxes decreased $438,000 or 44.9 percent in the second quarter of 2003 compared with the same period in 2002 due to a decrease in pretax book income from operations.

Income taxes decreased $99,000 or 3.3 percent in the first half of 2003 compared with the same period in 2002 for the same reason.

OTHER INCOME

Other income decreased $127,000 or 21.2 percent during the three months ended June 30, 2003 compared with the same period in 2002, as earnings from VY decreased due to the sale of the nuclear power plant to Entergy in 2002. See Note 2, Investment in Associated Companies, for further information.

Other income decreased by $44,000 or 3.8 percent in first half of 2003 when compared with the same period in 2002, for the same reason.

INTEREST CHARGES

Interest charges increased $258,000 or 16.9 percent in the second quarter of 2003 compared with the same period in 2002, due to increases in long-term debt balances arising from the issuance of $42.0 million of first mortgage bonds in December 2002.

Interest charges increased $498,000 or 16.3 percent in the first half of 2003 compared with the same period in 2002, for the same reason.

PREFERRED STOCK DIVIDENDS

Dividends paid on preferred stock decreased $10,000 for the quarter ended June 30, 2003 compared with the same period in 2002, due to redemptions of preferred stock during 2002 as discussed in this section under "Liquidity and

Capital Resources".

Dividends paid on preferred stock decreased $93,000 for the first half 2003 compared with the same period in 2002, for the same reason.

LIQUIDITY AND CAPITAL RESOURCES

In the six months ended June 30, 2003, we spent $9.9 million principally for expansion and improvements of our transmission, distribution and generation plant, and environmental expenditures. We expect to spend approximately $12.6 million during the remainder of 2003, principally for improvements to transmission, distribution and generation plant, and environmental expenditures.

During June 2003, the Company negotiated a 364-day revolving credit agreement (the "Fleet-Sovereign Agreement") with Fleet Financial Services ("Fleet") joined by Sovereign Bank. The Fleet-Sovereign Agreement is for $20.0 million, unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There were no amounts outstanding on the Fleet-Sovereign Agreement at June 30, 2003. The Fleet-Sovereign Agreement expires June 16, 2004. There was no non-utility short-term debt outstanding at June 30, 2003.

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

The Company completed a capital restructuring plan that reduced equity and high-priced debt during 2002 and resulted in debt and equity ratios closer to its targets of 50 percent debt and 50 percent equity. Significant transactions resulting from the restructuring plan included:

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

During March and June 2002, the Company repurchased $11.0 and $1.0 million, respectively, of the 7.32 percent Class E preferred stock outstanding;

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

On December 16, 2002, the Company issued $42 million principal amount of first mortgage bonds bearing interest at 6.04 percent per year and maturing on December 1, 2017.

The credit ratings of the Company's securities at June 30, 2003 were:

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

On August 29, 2002, Moody's upgraded the Company's senior secured debt rating to Baa1 from Baa2. The outlook for the ratings is stable. On September 29, 2002, Fitch Ratings upgraded the ratings of the Company's first mortgage bonds to BBB+

from BBB, with a stable outlook. On September 23, 2002, Standard and Poor's Ratings Services affirmed its BBB rating of the Company's senior secured debt, with a stable outlook.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

FUTURE OUTLOOK-COMPETITION 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;

increasing demand for customer choice;

consolidation through business combinations;

new regulations and legislation intended to foster competition, also known as restructuring;

changes in rules governing wholesale electricity markets; and

increasing volatility of wholesale market prices for electricity.

Power supply difficulties in some regulatory jurisdictions, such as California, and proposed changes in regional and national wholesale markets appear to have dampened any immediate push towards de-regulation in Vermont. We are unable to predict what form future restructuring legislation, if adopted, will take and what impact that might have on the Company, but it could be material.

PENSION

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

The Company's funding policy is to make voluntary contributions to its defined benefit plans before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company adopted a plan to make pension plan contributions totaling $2.0 million between September 1, 2002 and June 30, 2003, of which $2.0 million has been contributed to date. The Company intends to contribute up to an additional $2.8 million by December 31, 2003. The Company's pension costs and cash funding requirements are expected to continue at an equivalent or increased rate through 2004.

As a result of our plan asset experience, at December 31, 2002, the Company was required to recognize an additional minimum liability of $2.4 million, net of applicable income taxes, as prescribed by SFAS 87. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income ("OCI"), and did not affect net income for 2002. The charge to OCI may be restored through common equity in future periods to the extent fair value of trust assets exceeds the accumulated benefit obligation.

NEW ACCOUNTING STANDARDS

See Part I-Item 1, Note 6, "New Accounting Standards" for more information on the adoption of new accounting standards and the impact, or lack thereof, on the Company's financial position and operating results.

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 both historical costs and known and measurable changes, the Company is able to receive some rate relief for inflation. It does not receive immediate rate recovery relating to fixed costs associated with Company assets. Such fixed costs are recovered based on historic figures. Any effects of inflation on plant costs are generally offset by the fact that these assets are financed through long-term debt.

MARKET RISK

Our material power supply contracts and arrangements are principally with Hydro Quebec, MS and Vermont Yankee. At June 30, 2003, more than 90 percent of our estimated load requirements through 2006 are expected to be met by these contracts and arrangements, and by our own generation and other power supply resources, which reduces the Company's exposure to market prices.

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

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

A sensitivity analysis has been prepared to estimate the exposure to the market price risk of our electricity commodity positions. The MS contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133") and is effective through December 31, 2006. Management's estimate of the fair value of the future net benefit of this arrangement at June 30, 2003 is approximately $6.6 million. Assumptions used to calculate the future net benefit using the Blacks option valuation model include a risk-free interest rate of 3.4 percent, volatility equivalent to a weighted average from NEPOOL, which varies from 32 percent in the first year to 29 percent in the fourth year, and locked in forward commitment prices for 2003, with an estimated forward market price of approximately $43 per MWh for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Actual results may differ materially from the table below.

A sensitivity analysis has been prepared to estimate exposure to the market price risk of 9701, using the Black-Scholes model, over the next 13 years. Management's estimate of the fair value of the future net cost for this arrangement at June 30, 2003 is approximately $27.7 million. Assumptions used within the model include a risk-free interest rate of 3.97 percent, volatility equivalent to the weighted average from NEPOOL, which varies from 48 percent in the first year to 26 percent in year 13, locked in forward commitment prices for 2003, and an average of approximately 60,000 MWh per year, with an estimated forward market price of $59.81 per MWh during peak hours for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Quoted forward market prices for monthly peak power rates are not currently available beyond 2004. Actual results may differ materially from the table below.

The table below presents market risk estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in prices, which for the Company's derivatives discussed above totals approximately $3.0 million. Actual results may differ materially from the table below. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are not recognized in earnings until the derivative positions are settled.

Commodity Price Risk	At June 30, 2003 Fair Value	Market Risk
	(in thousands)	
Net short position	$ 21,160	$ 2,995

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 Controller 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 Controller and Treasurer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company (including its consolidated subsidiaries) required to be included in the Company's periodic SEC filings. There has been no change in the Company's internal control over financial reporting during the quarter ended June 30, 2003 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

GREEN MOUNTAIN POWER CORPORATION

JUNE 30, 2003

PART II - OTHER INFORMATION

ITEM 1. Legal Proceedings

See Notes 3, 4 and 5 of Notes to Consolidated Financial Statements

ITEM 2. Changes in Securities

NONE

ITEM 3. Defaults Upon Senior Securities

NONE

ITEM 4. Submission of Matters to a Vote of Security Holders

At the Annual Shareholders Meeting held May 15, 2003, no items were voted upon by Shareholders. Voting results for directors are listed below.

Shareholders elected the nominees listed below as Directors of this company, with votes cast as indicated.

Merrill O. Burns, votes for, 3,912,890; withheld authority, 261,594; abstentions, 787,473.

Christopher L. Dutton, votes for, 4,104,835; withheld authority, 69,649; abstentions, 787,473.

Directors continuing in office were Elizabeth A. Bankowski, Nordahl L. Brue, William H. Bruett, Lorraine E. Chickering, John V. Cleary, David R. Coates, and Euclid A. Irving.

ITEM 5. Other Information NONE

ITEM 6.
(A) EXHIBITS

Exhibit 31.1 and Exhibit 31.2, Certification by Officers of Financial Information and Disclosure Controls and Procedures required by Section 302 of the Sarbanes-Oxley Act of 2002 accompanies this quarterly report.

Exhibit 32.1, Certification by Officers of Financial Information and Internal Controls required by Section 906 of the Sarbanes-Oxley Act of 2002 accompanies this quarterly report.

(B) REPORTS ON FORM 8-K

The following filings on Form 8-K were filed by the Company on the topics and dates indicated:

A Form 8-K was filed July 15, 2003, announcing the Company's agreement with the Vermont Department of Public Service concerning its cost of service filing, and allowed rate of return.

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
(Registrant)

Date: August 11, 2003 /s/ Christopher L. Dutton

Christopher L. Dutton, Chief Executive Officer and President

Date: August 11, 2003 /s/ Robert J. Griffin

Robert J. Griffin, (as Principal Financial Officer)

Treasurer and Controller