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GREEN MOUNTAIN POWER CORP

Form 10-Q

August 10, 2001

August 9, 2001

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, 2001

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 (I.R.S. EMPLOYER  
IDENTIFICATION NO.)  
OR ORGANIZATION)

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, 2001  
\$3.33 1/3 PAR VALUE 5,634,840

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GREEN MOUNTAIN POWER CORPORATION  
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES  
AT AND FOR THE THREE AND SIX MONTHS ENDED JUNE 30,  
2001 AND 2000

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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	2000	SIX MONTHS ENDED JUNE 30	2001
(in thousands, except per share data)				
OPERATING REVENUES . . . . .	\$67,471	\$61,927	\$142,267	\$142,267
OPERATING EXPENSES				
Power Supply				
Vermont Yankee Nuclear Power Corporation . . . . .	5,737	8,726	19,422	19,422
Company-owned generation . . . . .	(133)	1,710	2,243	2,243
Purchases from others . . . . .	40,166	42,987	78,541	78,541
Other operating . . . . .	4,405	3,671	7,773	7,773
Transmission . . . . .	3,544	3,604	7,002	7,002
Maintenance . . . . .	2,078	1,553	3,535	3,535
Depreciation and amortization . . . . .	3,623	3,977	7,312	7,312
Taxes other than income . . . . .	1,915	1,765	3,903	3,903
Income taxes . . . . .	1,861	(3,069)	3,687	3,687
Total operating expenses . . . . .	63,196	64,924	133,418	133,418
OPERATING INCOME . . . . .	4,275	(2,997)	8,849	8,849

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OTHER INCOME				
Equity in earnings of affiliates and non-utility operations.	584	620	1,135	
Allowance for equity funds used during construction. . . . .	45	79	59	
Other income (deductions), net . . . . .	(47)	(91)	(74)	
TOTAL OTHER INCOME. . . . .	582	608	1,120	
INCOME BEFORE INTEREST CHARGES . . . . .	4,857	(2,389)	9,969	
INTEREST CHARGES				
Long-term debt . . . . .	1,547	1,647	3,095	
Other interest . . . . .	232	111	710	
Allowance for borrowed funds used during construction. . . . .	(41)	(42)	(103)	
TOTAL INTEREST CHARGES. . . . .	1,738	1,716	3,702	
INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS				
Dividends on preferred stock . . . . .	235	270	469	
Income from continuing operations. . . . .	2,884	(4,375)	5,798	
Loss on disposal of discontinued segment, including provisions for operating losses during phaseout period. . . . .	(150)	(1,530)	(150)	
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK . . . . .	\$ 2,734	\$ (5,905)	\$ 5,648	\$ (
Common stock data				
Basic earnings (loss) per share. . . . .	\$ 0.49	\$ (1.08)	\$ 1.01	\$
Diluted earnings (loss) per share. . . . .	0.47	(1.08)	0.98	
Cash dividends declared per share. . . . .	\$ 0.14	\$ 0.14	\$ 0.55	\$
Weighted average common shares outstanding-basic . . . . .	5,615	5,472	5,602	
Weighted average common shares outstanding-diluted . . . . .	5,777	5,472	5,759	
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS				
Balance - beginning of period. . . . .	\$ 2,639	\$13,046	\$ 493	\$ 1
Net Income (loss). . . . .	2,969	(5,635)	6,117	(
Cash Dividends-redeemable cumulative preferred stock . . . . .	(235)	(270)	(469)	(
Cash Dividends-common stock. . . . .	(771)	(752)	(1,539)	(
Balance - end of period. . . . .	\$ 4,602	\$ 6,389	\$ 4,602	\$

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

GREEN MOUNTAIN POWER CORPORATION  
CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE SIX MONTHS ENDED  
JUNE 30,

2001                      2000

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OPERATING ACTIVITIES:	(in thousands)	
Net income (loss) before preferred dividends . . . . .	\$ 6,117	\$ (1,916)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization . . . . .	7,312	8,144
Dividends from associated companies less equity income. .	21	(57)
Allowance for funds used during construction. . . . .	(162)	(223)
Amortization of purchased power costs . . . . .	2,008	3,058
Deferred income taxes . . . . .	(1,714)	1,145
Deferred revenues . . . . .	3,158	3,580
Deferred purchased power costs. . . . .	(1,966)	(3,103)
Accrued purchase power contract option call . . . . .	(2,376)	12,478
Provision for loss on segment disposal. . . . .	150	1,530
Deferred arbitration costs. . . . .	108	(2,157)
Earnings cap deferral and rate levelization liability . .	4,869	-
Environmental and conservation deferrals, net . . . . .	(1,377)	(826)
Changes in:		
Accounts receivable . . . . .	1,034	1,347
Accrued utility revenues. . . . .	708	597
Fuel, materials and supplies. . . . .	(261)	226
Prepayments and other current assets. . . . .	1,578	2,064
Accounts payable. . . . .	(1,346)	1,947
Accrued income taxes payable and receivable . . . . .	2,125	(2,801)
Other current liabilities . . . . .	389	(3,888)
Other . . . . .	(583)	196
	-----	-----
Net cash provided by continuing operations. . . . .	19,793	21,341
Net change in discontinued segment. . . . .	(1,533)	(86)
	-----	-----
Net cash provided by operating activities . . . . .	18,260	21,255
 INVESTING ACTIVITIES:		
Construction expenditures . . . . .	(5,224)	(5,983)
Investment in nonutility property . . . . .	(101)	(97)
	-----	-----
Net cash used in investing activities . . . . .	(5,325)	(6,080)
	-----	-----
 FINANCING ACTIVITIES:		
Issuance of common stock. . . . .	806	561
Investment in certificate of deposit, pledged for revolver.	(500)	-
Power supply option obligation. . . . .	744	-
Reduction in long-term debt . . . . .	(1,700)	(1,700)
Short-term debt, net. . . . .	(10,608)	(7,900)
Cash dividends. . . . .	(2,008)	(2,039)
	-----	-----
Net cash used in financing activities . . . . .	(13,266)	(11,078)
	-----	-----
Net increase(decrease) in cash and cash equivalents . . . .	(330)	4,097
Cash and cash equivalents at beginning of period. . . . .	341	696
	-----	-----
Cash and cash equivalents at end of period. . . . .	\$ 11	\$ 4,793
	=====	=====
 SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid year-to-date for:		
Interest (net of amounts capitalized) . . . . .	\$ 3,720	\$ 3,258
Income taxes, net . . . . .	3,292	1,191

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

PART I, ITEM 1

GREEN MOUNTAIN POWER CORPORATION  
CONSOLIDATED BALANCE SHEETS

UNAUDITED

AT JUNE 30,

DECEMBER 31,

2001                      2000                      2000

(in thousands)

ASSETS

UTILITY PLANT

Utility plant, at original cost . . . . .	\$295,133	\$287,105	\$291,107
Less accumulated depreciation . . . . .	114,380	107,934	110,273
Net utility plant . . . . .	180,753	179,171	180,834
Property under capital lease . . . . .	6,449	7,038	6,449
Construction work in progress . . . . .	6,955	7,037	7,389
Total utility plant, net . . . . .	194,157	193,246	194,672

OTHER INVESTMENTS

Associated companies, at equity . . . . .	14,322	14,708	14,373
Other investments . . . . .	6,598	6,043	6,357
Total other investments . . . . .	20,920	20,751	20,730

CURRENT ASSETS

Cash and cash equivalents . . . . .	11	4,755	341
Certificate of deposit, pledged as collateral . . . . .	15,936	-	15,437
Accounts receivable, customers and others, less allowance for doubtful accounts of \$613, \$398, and \$463 . . . . .	24,560	17,155	22,365
Accrued utility revenues . . . . .	6,385	6,371	7,093
Fuel, materials and supplies, at average cost . . . . .	4,316	3,063	4,056
Prepayments . . . . .	889	340	2,525
Income tax receivable . . . . .	-	4,042	1,613
Other . . . . .	278	178	222
Total current assets . . . . .	52,375	35,904	53,652

DEFERRED CHARGES

Demand side management programs . . . . .	6,485	6,586	6,358
Purchased power costs . . . . .	24,318	9,663	11,789
Pine Street Barge Canal . . . . .	12,370	8,700	12,370
Other . . . . .	15,749	16,598	15,519
Total deferred charges . . . . .	58,922	41,547	46,036

NON-UTILITY

Cash and cash equivalents . . . . .	-	39	-
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Other current assets . . . . .	8	8	8
Property and equipment . . . . .	251	253	252
Business segment held for disposal . . . . .	-	8,033	-
Other assets . . . . .	847	1,294	1,258
	-----	-----	-----
Total non-utility assets . . . . .	1,106	9,627	1,518
	-----	-----	-----
TOTAL ASSETS . . . . .	\$327,480	\$301,075	\$316,608
	=====	=====	=====

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

GREEN MOUNTAIN POWER CORPORATION  
CONSOLIDATED BALANCE SHEETS

UNAUDITED

AT JUNE 30, DECEMBER 31,

2001 2000 2000

(in thousands except share data)

CAPITALIZATION AND LIABILITIES

CAPITALIZATION

Common stock equity

Common stock, \$3.33 1/3 par value,  
authorized 10,000,000 shares (issued  
5,641,009, 5,498,037 and 5,582,552) . . . . .

\$ 18,802 \$ 18,327 \$ 18,608

Additional paid-in capital . . . . .

73,933 72,913 73,321

Retained earnings . . . . .

4,602 6,389 493

Treasury stock, at cost (15,856 shares) . . . . .

(378) (378) (378)

Total common stock equity . . . . .

96,959 97,251 92,044

Redeemable cumulative preferred stock . . . . .

12,560 12,795 12,560

Long-term debt, less current maturities . . . . .

70,400 80,100 72,100

Total capitalization . . . . .

179,919 190,146 176,704

CAPITAL LEASE OBLIGATION . . . . .

6,449 7,038 6,449

CURRENT LIABILITIES

Current maturities of preferred stock . . . . .

235 1,640 235

Current maturities of long-term debt . . . . .

9,700 6,700 9,700

Short-term debt . . . . .

4,892 - 15,500

Accounts payable, trade and accrued liabilities . . . . .

8,985 6,400 7,755

Accounts payable to associated companies . . . . .

5,932 8,808 8,510

Earnings cap deferral . . . . .

925 - -

Customer deposits . . . . .

816 379 696

Purchased power call option liability . . . . .

5,901 12,478 8,276

Interest accrued . . . . .

1,075 1,151 1,150

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Energy East power supply obligation. . . . .	16,163	-	15,419
Deferred revenues. . . . .	3,158	3,580	-
Other. . . . .	1,959	3,430	1,103
Total current liabilities. . . . .	59,741	44,566	68,344
DEFERRED CREDITS			
SFAS 133 liability . . . . .	15,714	-	-
Accumulated deferred income taxes. . . . .	24,071	26,487	25,644
Unamortized investment tax credits . . . . .	3,554	3,836	3,695
Pine Street Barge Canal site cleanup . . . . .	11,080	8,910	11,554
Other. . . . .	21,374	20,092	20,901
Rate levelization liability. . . . .	3,944	-	-
Total deferred credits . . . . .	79,737	59,325	61,794
COMMITMENTS AND CONTINGENCIES			
NON-UTILITY			
Liabilities of discontinued segment, net . . . . .	1,634	-	3,317
Total non-utility liabilities. . . . .	1,634	-	3,317
 TOTAL CAPITALIZATION AND LIABILITIES . . . . .	 \$327,480	 \$301,075	 \$316,608

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

GREEN MOUNTAIN POWER CORPORATION  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS  
JUNE 30, 2001

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 includes 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 annual report for 2000 filed on Form 10-K, are adequate to make the information presented not misleading.

The Vermont Public Service Board ("VPSB"), the regulatory commission in Vermont, sets the rates we charge our customers for their electricity. Historically we have charged our customers higher rates for billing cycles in December through March and lower rates for the remaining months. These are called seasonally differentiated rates. In order to eliminate the impact of the seasonally differentiated rates, we defer some of the revenues from those four months and recognize them in later periods when we have lower revenues or higher costs. By deferring certain revenues we are able to better match our revenues to our costs. On June 30, 2001, there was deferred revenue of \$3.2 million,

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compared with \$3.6 million at June 30, 2000.

In the Company's most recent rate case settlement the VPSB ordered that seasonal rates be eliminated in April 2001, which is expected to generate approximately \$7.0 million in additional cash flow in 2001. Such deferred revenue was intended by the VPSB to be used to offset increased costs during 2001, 2002 and 2003, increasing the likelihood of the Company earning its allowed rate of return in those years. Approximately \$3.9 million of revenue arising as a result of the elimination of seasonal rates was deferred during the second quarter of 2001.

The Company's earnings from electric operations are subject to an earnings cap equal to its allowed rate of return of 11.25%. The Company's policy is to review its quarterly results and to defer any revenues that are probable of causing earnings to exceed an 11.25% rate of return ("excess earnings") for the year. As a result of our review, we deferred \$0.9 million of revenue and recorded a regulatory liability for excess earnings in the same amount during the quarter ended June 2001. Under a settlement agreement with the Vermont Department of Public Service ("DPS" or the "Department"), and approved by the VPSB, any excess earnings amounts will be used to write off regulatory assets.

The Company reviews its deferred revenue balances arising from excess earnings and rate levelization each quarter and adjusts those balances as necessary to reflect the Company's current estimate of its ultimate regulatory liability. See the discussion under "Commitments and Contingencies - Retail Rate Cases" for further information.

Certain line items on the prior years' 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.

### UNREGULATED OPERATIONS

We have or have had unregulated, wholly-owned subsidiaries: Northern Water Resources, Inc. ("NWR", formerly known as Mountain Energy, Inc.); Green Mountain Propane Gas Company Limited ("GMPG"); GMP Real Estate Corporation; and Green Mountain Resources, Inc. ("GMRI"). On June 30, 1999, we decided to sell the assets of NWR, and report its results as income (loss) from operations of a discontinued segment. See the disclosure under the caption "Segments and Related Information" for a more detailed discussion. We also have a rental water heater program that is not regulated by the VPSB. The results of the operations of these unregulated subsidiaries (excluding NWR) and the rental water heater program are included in earnings of affiliates and non-utility operations in the Other Income section of the Consolidated Comparative Income Statements.

### 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")  
Percent ownership: 17.9% common



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	Three months ended June 30		Six months ended June 30	
	2001	2000	2001	2000
	-----	-----	-----	-----
(in thousands)				
Gross Revenue . . . . .	\$57,031	\$44,702	\$97,995	\$85,394
Net Income Applicable to Common Stock	1,574	1,639	3,124	3,383
Equity in Net Income .	287	301	560	615

On October 15, 1999, the owners of VY accepted a bid from AmerGen Energy Company for the VY generating plant, intending to complete the sale before December 2000. AmerGen and the DPS negotiated a revised offer in November 2000, which was subsequently dismissed as insufficient by the VPSB in February 2001. Prior to the dismissal of the AmerGen offer, Entergy Nuclear Inc. had also made an offer, secured by a bond which was acceptable to the VPSB, and two other companies indicated they would participate in an auction, if held. VY has initiated an auction of the plant. The terms and conditions of a sale of the plant by auction, if any, are unknown at this time.

If the plant is sold, the Company would continue equity ownership of VY, and would expect to enter into a power supply agreement with the new plant owners.

VERMONT ELECTRIC POWER COMPANY, INC. ("VELCO")  
 Percent ownership: 29.5% common  
 30.0% preferred

	Three months ended June 30		Six months ended June 30	
	2001	2000	2001	2000
	-----	-----	-----	-----
(in thousands)				
Gross Revenue . . . . .	\$8,548	\$7,425	\$15,718	\$14,140
Net Income . . . . .	309	310	552	583
Equity in Net Income.	91	90	146	174

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.

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 the Company's compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site.

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### 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 ("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, 2001, our total expenditures related to the Pine Street site since 1982 were approximately \$24.0 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 awaiting 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 \$12.4 million over the next 32 years. 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 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 recovery 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

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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". The VPSB Order released January 23, 2001 and discussed below did not change the status of Pine Street cost recovery.

### RETAIL RATE CASE

On May 8, 1998, we filed a request with the VPSB to increase our retail rates by 12.93 percent due to higher power costs, the cost of the January 1998 ice storm, and investments in new plant and equipment (the "1998 rate case").

The Company reached a final settlement agreement with the Department in the 1998 rate case during November 2000. The final settlement agreement 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 over the past three years;

\* 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 annual power supply costs increase in excess of \$3.75 million over forecasted levels;

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

\* Seasonal rates were eliminated in April 2001, which is expected to generate approximately \$7.0 million in additional cash flow in 2001 that can be utilized to offset potential increased costs during 2001, 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; and

\* The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the Company's 1997 rate case. The Company agreed to an earnings cap for its electric operations in an amount equal to its allowed rate of return of 11.25 percent. Amounts earned over the cap will be used to write-off regulatory assets.

On January 23, 2001, the VPSB Order (the "Settlement Order") approved the Company's settlement with the Department, with two additional conditions:

\* The Settlement Order provided that the Company and its customers 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; and

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

### 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.

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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 quarter of 2001, Hydro-Quebec exercised option A and option B, calling for deliveries of 134,592 MWh during June, July and August of 2001. The cumulative amount of power purchased or called to be purchased by Hydro-Quebec under option B is approximately 432,000 MWh. Approximately \$6.6 million is currently being provided annually in rates to cover the net cost of 9701 calls by Hydro-Quebec, and is recognized ratably over 2001. The Company recognized \$3.3 million in expense during the six months ended June 30, 2001 to reflect these estimated costs. A regulatory asset of \$3.3 million was established for the remaining estimated difference between the option exercise price and the expected cost of replacement power for 2001. In conjunction with the Settlement Order, Hydro-Quebec agreed not to call option B during 2002. If estimated costs of fulfilling the Hydro-Quebec option calls exceed amounts recovered in rates and/or amounts previously recorded, the excess cost would be immediately charged against earnings. No charge for excess cost was required during the first half of 2001. The Company has purchased power sufficient to fulfill the 9701 option calls for this summer, and no charges in excess of amounts provided in rates or previously recorded are anticipated for the remainder of 2001. It is possible our estimate of future power supply costs could differ materially from actual results.

Hydro-Quebec's option to curtail 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 through 2015, 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.

During 1999, the Company had accrued expected losses for 2000 for disallowed Hydro-Quebec power supply contracts pursuant to VPSB orders. Results for the three and six months ended June 30, 2000 do not reflect any disallowed Hydro-Quebec power supply costs. If the 1999 accruals, consistent with generally accepted accounting principles, had not been made, power supply costs would have been \$1.9 and \$3.8 million higher for the three and six months ended June 30, 2000, respectively.

### POWER SUPPLY AND TRANSMISSION

Company-owned generation expenses decreased \$1.8 million in the second quarter of 2001 compared with the same period in 2000 primarily due to a reimbursement by the New England Independent System Operator ("ISO") of Company-owned generation expenses recorded in previous periods and because of the unavailability of transmission equipment beginning in the second quarter of 2000 that required running generation to maintain system reliability. The Company requested reimbursement of its costs of running its units for system reliability from the ISO. During the first quarter of 2001, the Company recorded a receivable and reduced Company-owned generation expense by \$1.0 million, representing such fuel and operation and maintenance costs due from the ISO. The Company received \$1.9 million from the ISO in July 2001 and recorded the additional \$0.9 million as a reduction to Company-owned generation expense in the second quarter of 2001.

A FERC ruling in December 2000 required the ISO to revise its installed capability ("ICAP") deficiency charge of \$0.17 per kw month to \$8.75 per kw month retroactive to August 1, 2000. On January 10, 2001, FERC stayed its order "to ensure that bills for past periods will not be assessed until the Commission has considered the pending requests for rehearing, which, if successful, would then require extensive refunds and surcharges." On March 6, 2001, FERC issued an Order on Rehearing in which it partly reversed itself on the ICAP charge. Although the FERC first concluded that a \$8.75 charge is reasonable and that the charge would remain in place until the ISO supports an acceptable superseding proposal, the FERC then concluded that reinstating the \$8.75 would have an

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adverse cost impact, and should be effective only as of April 1, 2001. The FERC allowed the \$8.75 charge to become effective on April 1, 2001 until the effective date of any superseding charge that the FERC might accept. In March 2001, a federal court issued a stay preventing reinstatement of the \$8.75 charge, after sixteen New England utilities and energy companies protested the increased penalty. The federal court lifted the stay but ordered FERC to further justify its decision and said that a \$5 per kW month rate might be more appropriate. Management cannot determine the ultimate outcome of these regulatory and judicial proceedings at this time.

The Company's generation and entitlements cover the majority of its ICAP requirements, except for its obligations under the 9701 arrangement with Hydro-Quebec. The Company has purchased ICAP associated with 2001 obligations for its 9701 arrangement at an average price of approximately \$4.00 per kW month. The Company has also arranged to purchase its anticipated 9701 ICAP needs during 2002 at an average cost of \$2.60 per kW month, and approximately 50 percent of its anticipated 9701 ICAP needs during 2003 at a cost of \$2.85 per kW month.

On April 17, 2001, an Arbitration Tribunal issued its decision in the arbitration brought by a group of Vermont electric companies and municipal utilities, known as the Vermont Joint Owners (VJO), against Hydro-Quebec for its failure to deliver electricity pursuant to the VJO/Hydro-Quebec power supply contract during the 1998 ice storm. The Company is a member of the VJO.

In its award, the Arbitration Tribunal agreed partially with Hydro-Quebec and partially with the VJO. In the decision, the Tribunal concluded (i) the VJO/Hydro-Quebec power supply contract remains in effect and Hydro-Quebec is required to continue to provide capacity and energy to the Company under the terms of the VJO contract, which expires in 2015 and (ii) Hydro-Quebec is required to return certain capacity payments to the VJO.

As of June 30, 2001, the Company had deferred a total of \$4.6 million, representing its share of costs related to the pursuit of arbitration against Hydro-Quebec. The Company has received an accounting order from the VPSB providing for the deferral of these charges, subject to final determination in a future rate proceeding.

On July 23, 2001, the Company received approximately \$3.2 million representing its share of refunded capacity payments from Hydro-Quebec. These proceeds reduced related deferred assets at June 30, 2001, leaving a balance of unrecovered arbitration costs of approximately \$1.4 million. We believe it is probable that this balance will ultimately be recovered in rates.

#### 4. SEGMENTS AND RELATED INFORMATION

The Company has two reportable segments, the electric utility and NWR. 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, 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, 1999, we classified NWR's net assets and liabilities as "Business Segment Held for Sale", reflecting the Company's intent to sell NWR's assets. Previously, investment in NWR appeared as a separate caption, "Equity Investment in Energy Related Business" in the nonutility section of the consolidated balance sheet.

During 2000, the Company recorded losses of \$6.5 million, or \$1.19 per share to reflect revised estimates and actual sales of most of NWR's energy generation and energy efficiency assets. During the quarter ended June 30, 2001, the Company recorded a provision for loss of \$0.2 million or 3 cents per share related to a revision to its estimate of the ultimate costs of warranty obligations on its waste-water investments. The provisions for loss from discontinued operations reflect the Company's most recent estimate. The ultimate loss remains subject to the sale or other disposition of NWR's

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remaining assets and liabilities, primarily patents and warranty claims, and tax liabilities, and could exceed amounts recorded. Results of operations for NWR are now reported under "Loss on disposal of discontinued segment, net of applicable income taxes". Provisions for loss on disposal are reported under "Loss on disposal of discontinued segment, net of applicable income taxes". Segment information compared with the Company's results includes the following:

	Three months ended June 30		Six months ended June 30	
	2001	2000	2001	2000
-----				
(in thousands, except per share data)				
External revenues				
Electric utility . . . . .	\$67,471	\$61,927	\$142,267	\$129,639
NWR segment. . . . .	35	521	104	618
Net income (loss) from operations				
Electric utility . . . . .	\$ 2,884	\$ (4,375)	\$ 5,798	\$ (925)
NWR segment. . . . .	(150)	(1,530)	(150)	(1,530)
-----				
Consolidated net income (loss). . . . .	\$ 2,734	\$ (5,905)	\$ 5,648	\$ (2,455)
=====				
Basic earnings (loss) per share				
Discontinued operations. . . . .	\$ (0.03)	\$ (0.28)	\$ (0.03)	\$ (0.28)
Continuing operations. . . . .	0.52	(0.80)	1.04	(0.17)
Diluted earnings per share				
Discontinued operations. . . . .	\$ (0.03)	\$ (0.28)	\$ (0.03)	\$ (0.28)
Continuing operations. . . . .	0.47	(1.08)	0.98	(0.45)

### 5. NEW ACCOUNTING STANDARD - SFAS 133

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities. 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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement or other comprehensive income, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133, as amended by SFAS 137, was effective for the Company beginning the first quarter of 2001. SFAS 133 must be applied to (a) derivative instruments and (b) either all derivative instruments embedded in hybrid contracts or those embedded instruments that were issued, acquired, or substantively modified on or after January 1, 1998 or January 1, 1999 (as elected by the Company).

The objective of the Company's risk management program is to protect cash flow and earnings by minimizing risk. Permitted transactions 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 risk of fossil fuel price increases as well as the risk of spot market electricity price increases. Futures, swaps and forward contracts are used to hedge market prices should option calls by Hydro-Quebec be exercised. The Company's risk management policy specifies risk measures, the

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amount of tolerable risk exposure, and limits to transaction authority.

The Company's 9701 arrangement with Hydro-Quebec that grants Hydro-Quebec an option to call for energy deliveries at prices currently below estimated future market rates through 2015 is a derivative under SFAS 133. We sometimes use futures contracts (derivatives) to hedge forecasted wholesale sales of electric power, including the 9701 arrangement. The Company also has a power purchase and supply agreement with Morgan Stanley Capital Group, Inc. ("MS") to hedge the fair value of fossil fuel prices that is a derivative under SFAS 133.

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, and as a result, we do not anticipate SFAS 133 to cause earnings volatility. At June 30, 2001, the Company had a liability reflecting the negative market position of the two derivatives described above, as well as a corresponding regulatory asset of approximately \$15.7 million related to the derivatives discussed above. The Company believes that the regulatory asset is probable of recovery. The regulatory asset 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.

### 6. OTHER NEW ACCOUNTING STANDARDS

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 141, Business Combinations ("SFAS 141"), and Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS 142"). SFAS 141 requires the use of the purchase method to account for business combinations and uses a nonamortization approach to purchased goodwill. SFAS 142 establishes requirements for evaluating goodwill and other intangible assets for impairment and provides further guidance on accounting for intangible assets. The Company does not expect the application of these accounting standards, when adopted, to materially impact its financial position or results of operations.

The FASB is expected to issue a new statement on accounting standards in August 2001 for "Accounting for the Impairment or Disposal of Long-lived Assets and for Obligations Associated with Disposal Activities", which will provide guidance on accounting for nuclear plant decommissioning costs. The Company has not yet determined what impact, if any, the proposed accounting standard will have on its investment in VY.

### 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 period presented. The Company established a stock incentive plan for all employees during the year ended December 31, 2000, and options granted are exercisable over vesting schedules of between one and four years.

	Three months ended		Six months ended	
	June 30		June 30	
	2001	2000	2001	2000
	-----	-----	-----	-----
(in thousands)				
Net income (loss) before preferred dividends.	\$2,969	\$(5,635)	\$6,117	\$(1,916)
Preferred stock dividend requirement. . . . .	235	270	469	539
	-----	-----	-----	-----

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Net income (loss) applicable to common stock . . . . .	\$2,734	\$ (5,905)	\$5,648	\$ (2,455)
	=====	=====	=====	=====
Average number of common shares-basic . . . . .	5,615	5,472	5,602	5,455
Dilutive effect of stock options . . . . .	162	-	158	-
Anti-dilutive stock options . . . . .	-	-	-	-
	-----	-----	-----	-----
Average number of common shares-diluted . . . . .	5,777	5,472	5,760	5,455
	=====	=====	=====	=====

GREEN MOUNTAIN POWER CORPORATION  
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL  
CONDITION AND RESULTS OF OPERATIONS  
JUNE 30, 2001

PART I -- ITEM 2

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.

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 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.



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	Three months ended		Six months ended	
	June 30		June 30	
	2001	2000	2001	2000
	-----	-----	-----	-----
Utility business . . .	\$ 0.51	\$(0.83)	\$ 0.99	\$(0.22)
Unregulated businesses	0.02	0.03	0.05	0.05
	-----	-----	-----	-----
Earnings(loss) from: .	0.52	(0.80)	1.04	(0.17)
Continuing operations				
Discontinued segment .	(0.03)	(0.28)	(0.03)	(0.28)
	-----	-----	-----	-----
Basic earnings				
(loss) per share . .	\$ 0.49	\$(1.08)	\$ 1.01	\$(0.45)
	=====	=====	=====	=====

UTILITY BUSINESS

The Company recorded basic earnings per share from utility operations of \$0.51 in the quarter ended June 30, 2001, compared with a loss of \$0.83 per share in the second quarter of 2000.

The second quarter earnings improvement, compared with the same period for 2000, reflects a significant reduction in power supply costs and higher operating revenues. Power supply costs were \$7.7 million lower in the second quarter of 2001, primarily due to decreased costs associated with the management of the Company's long-term power supply sale commitment to Hydro-Quebec. Retail operating revenues for the quarter increased \$2.0 million compared with the same period in 2000, reflecting a 3.42 percent retail rate increase approved by the Vermont Public Service Board (the "VPSB") in January 2001 and a 0.6 percent increase in retail electricity sales.

Basic earnings per share from utility operations for the six months ended June 30, 2001 were \$0.99 compared with a loss per share of \$0.22 for the same period in 2000, due to the same factors influencing second quarter results. The Company had previously accrued losses for disallowed Hydro-Quebec power supply costs pursuant to VPSB orders. Results for the six months ended June 30, 2000 do not reflect any disallowed Hydro-Quebec power supply costs. If these accruals, consistent with generally accepted accounting principles, had not been made in prior periods, power supply costs would have been \$1.9 and \$3.8 million higher, respectively, for the three and six months ended June 30, 2000.

UNREGULATED BUSINESSES

Earnings from unregulated businesses included in results from continuing operations for the three and six months ended June 30, 2001 were slightly lower than during the same period in 2000. A financial summary for these businesses, excluding NWR, follows:

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	Three months ended June 30		Six months ended June 30	
	2001	2000	2001	2000
	-----	-----	-----	-----
(in thousands)				
Revenue . . . .	\$ 251	\$ 258	\$ 510	\$ 521
Expense . . . .	131	117	256	242
	-----	-----	-----	-----
Net Income . .	\$ 120	\$ 141	\$ 254	\$ 279
	=====	=====	=====	=====

DISCONTINUED SEGMENT OPERATIONS

As of June 30, 1999, the Company decided to sell or dispose of NWR, a wholly owned subsidiary that invested in energy generation, energy efficiency and wastewater treatment businesses. Its results are reported separately after income (loss) from continuing operations. NWR recognized an additional \$0.2 million as a provision for loss for the three and six months ended June 30, 2001 reflecting revised estimates of losses on warranty liabilities. The ultimate loss remains subject to the sale or other disposition of NWR's remaining assets and liabilities, primarily patents and warranty claims and tax liabilities, and could exceed amounts recorded. Most of NWR's energy generation and energy efficiency assets have been sold. The operating loss for the three months ended June 30, 2001 would have been approximately \$0.3 million compared with a loss of \$0.2 million for the same period a year ago. The operating loss for the six months ended June 30, 2001 would have been approximately \$0.4 million compared with a loss of \$1.1 million for the same period in 2000.

OPERATING REVENUES AND MWH SALES

Our revenues from operations, megawatthour ("MWh") sales and average number of customers for the three and six months ended June 30, 2001 and 2000 are summarized below:

	Three months ended June 30		Six months ended June 30	
	2001	2000	2001	2000
	-----	-----	-----	-----
(dollars in thousands)				
Operating revenues				
Retail . . . . .	\$ 50,453	\$ 43,535	\$ 102,406	\$ 93,085
Sales for Resale . . .	20,760	17,630	42,598	\$ 34,930
Other . . . . .	1,126	762	2,131	\$ 1,624
	-----	-----	-----	-----
Total Operating Revenues.	\$ 72,339	\$ 61,927	\$ 147,135	\$ 129,639
	=====	=====	=====	=====
MWh sales-Retail . . . . .	459,144	456,550	977,405	974,316
MWh sales for Resale . . .	545,288	588,275	1,183,384	1,155,960
	-----	-----	-----	-----
Total MWh Sales . . . . .	1,004,432	1,044,825	2,160,789	2,130,276
	=====	=====	=====	=====

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Average Number of Customers	Three months ended June 30		Six months ended June 30	
	2001	2000	2001	2000
	-----	-----	-----	-----
Residential . . . . .	73,075	72,093	73,130	72,127
Commercial and Industrial	12,998	12,672	12,957	12,603
Other . . . . .	66	64	65	64
	-----	-----	-----	-----
Total Number of Customers. .	86,139	84,829	86,152	84,794
	=====	=====	=====	=====

### REVENUES

Revenues from operations in the second quarter of 2001 increased 9.0 percent or \$5.5 million compared with the same period in 2000. Operating revenues result from retail and wholesale sales of electricity.

Retail revenues in the second quarter of 2001 were \$2.1 million or 4.7 percent higher compared with the same period in 2000, reflecting a 3.42 percent rate increase effective January 2001, and a 0.6 percent increase in retail MWh sales. Sales of electricity decreased by 0.4 percent to small commercial and industrial customers, decreased by 2.6 percent to residential customers and increased 3.9 percent to lower margin industrial customers during the second quarter of 2001 compared with the same period in 2000. Retail revenues for the six months ended June 30, 2001 were \$4.5 million or 4.8 percent higher when compared with the same period in 2000, reflecting the Settlement Order rate increase and increased retail MWh sales of approximately 0.3 percent.

We sell wholesale electricity to others for resale. Our revenue from wholesale sales of electricity increased \$3.1 million in the second quarter of 2001 compared with the same period in 2000, and increased \$7.7 million for the first half of 2001 compared with the same period in 2000. The increases were due primarily to increased sales under a power purchase and supply agreement between the Company and Morgan Stanley Capital Group, Inc. ("MS"), and increased sales under various arrangements with Hydro-Quebec. Under the MS agreement, we sell power to MS at predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements.

### OPERATING EXPENSES

#### POWER SUPPLY EXPENSES

Power supply expenses decreased 15.0 percent or \$7.7 million in the second quarter of 2001 over the same period in 2000.

Power supply expenses at Vermont Yankee decreased 34.3% or \$3.0 million during the second quarter of 2001 compared with the second quarter of 2000, primarily due to a scheduled outage during 2001. Vermont Yankee scheduled outage costs are deferred and amortized over an eighteen month refueling cycle. A proposed sale of the generating plant is discussed under Part I, Item 2, "Investment in Associated Companies".

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Company-owned generation expenses decreased \$1.8 million in the second quarter of 2001 compared with the same period in 2000 primarily due to a reimbursement by the New England Independent System Operator ("ISO") of Company-owned generation expenses recorded in previous periods and because of the unavailability of transmission equipment beginning in the second quarter of 2000 that required running generation to maintain system reliability.

The cost of power that we purchased from other companies decreased 6.6 percent or \$2.8 million in the second quarter of 2001 compared with the same period in 2000. This was primarily due to increased power supply costs of \$2.9 million during 2000 to replace power sold to Hydro-Quebec under a previous arrangement ("9701"), and increased costs of \$4.0 million during 2000 due to changes in power supply market conditions that resulted in a decline in the value of energy resources, partially offset by increases in costs during 2001 for power sold to MS under the power purchase and supply agreement.

Power supply costs were also lower during the second quarter of 2001 compared with the same period in 2000 due to a refund of certain administrative costs from New England Power Pool, the former wholesale electricity market clearinghouse replaced by the ISO, and lower costs from independent power producers reflecting declines in precipitation during the quarter.

The 9701 arrangement allows Hydro-Quebec to exercise an option to purchase power from the Company at energy prices based on a 1987 contract. During the first quarter of 2001, Hydro-Quebec exercised its purchase option for delivery of 134,592 MWh during the months of June, July and August of 2001. The Settlement Order approved by the VPSB includes revenues in 2001 sufficient to provide for net costs of replacing power purchased by Hydro-Quebec of approximately \$6.6 million annually. The Company recognized \$1.7 million in expense during the quarter ended June 30, 2001 to reflect these estimated costs. A regulatory asset of \$3.3 million was established for the remaining estimated difference between the option exercise price and the expected cost of replacement power for 2000 to be recovered during 2001. If the estimated costs of power purchased to supply Hydro-Quebec option calls exceed amounts recovered in rates and/or amounts previously recorded, the excess cost would be immediately charged against earnings. No charge for excess cost was required during the first half of 2001. The Company has purchased power sufficient to fulfill the 9701 calls for this summer, and no charges in excess of amounts provided in rates or previously recorded are anticipated for the remainder of 2001. The net cost of power to supply all 9701 option calls during 2001 is estimated at approximately \$8.4 million. It is possible our estimate of future power supply costs could differ materially from actual results. Power supply expenses for the first half of 2001 were unchanged compared with the first half of 2000.

Power supply expense at Vermont Yankee decreased \$3.5 million or 20.2 percent for the first half of 2001 compared with the first half of 2000, primarily due to a scheduled outage at the plant during 2001. Vermont Yankee scheduled outage costs are deferred and amortized over an eighteen month refueling cycle.

Company-owned generation expenses decreased \$0.7 million or 29.9 percent in the first half of 2001 compared with the same period in 2000. During 2001, the Company recorded a reduction of generation expense of approximately \$1.9 million for its costs of running peak generation facilities for system reliability and we received reimbursement of these amounts from the ISO in July 2001. This reduction was partially offset by increased generation expense in the first quarter of 2001 caused by higher fuel costs.

Purchased power expense increased \$4.6 million or 5.8 percent in the first half of 2001 compared with the first half of 2000. Power supply costs to supply increased wholesale sales of electricity under arrangements with MS and Hydro-Quebec, and for energy purchased to cover potential shortfalls due to transmission system operating requirements caused the increase. Higher energy prices also contributed to the increase in power supply costs. These increases were offset in part by decreased costs of managing the 9701 arrangement during 2001. Both the 9701 arrangement and our forward purchase contracts are considered derivative instruments as defined by SFAS 133. On April 11, 2001,

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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, 2001, the Company had a regulatory asset of approximately \$15.7 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.

### OTHER OPERATING EXPENSES

Other operating expenses increased 20.0 percent or \$0.7 million in the second quarter of 2001 compared with the same period in 2000. The increase reflects higher benefit costs and increased reserves for medical benefits and contingencies. Other operating expenses increased 6.5 percent or \$0.5 million in the first six months of 2001 compared with the same period in 2000 for the same reasons, offset in part by reduced regulatory commission expense.

### TRANSMISSION EXPENSES

Transmission expenses decreased by approximately \$0.1 million or 1.7 percent for the three months ended June 30, 2001 compared with the same period in 2000 due to minor reductions in congestion charges. Transmission expenses decreased by approximately \$0.1 million or 1.2 percent for the six months ended June 30, 2001, compared with the same period in 2000 for the same reason. Congestion charges recorded in the first six months of 2001 and 2000 reflect the lack of adequate transmission or generation capacity in certain locations within New England, and these charges are allocated to all ISO New England members. The Company is unable to predict the magnitude or duration of future congestion charge allocations, but amounts could be material.

### DEPRECIATION AND AMORTIZATION EXPENSES

Depreciation and amortization expenses decreased \$0.4 million or 8.9 percent during the second quarter of 2001 compared with the same period in 2000. The reduction is primarily due to decreased amortization of demand side management regulatory assets.

Depreciation and amortization expenses decreased \$0.8 million or 10.2 percent during the first six months of 2001 compared with the same period in 2000 for the same reason.

### TAXES OTHER THAN INCOME TAXES

Other taxes increased 8.5 percent or \$0.2 million in the second quarter of 2001 compared with the same period in 2000, primarily due to increases in gross revenue tax. Other taxes increased 3.0 percent or \$0.1 million for the first six months of 2001 compared with the same period in 2000 for the same reason.

### INCOME TAXES

Income taxes increased \$4.9 million in the second quarter of 2001 compared with the same period in 2000 due to an increase in pretax book income. Income taxes increased \$4.5 million for the first six months of 2001 compared with the same period in 2000 for the same reason.

### OTHER INCOME

Other income did not change significantly for the three months ended June 30, 2001 compared with the same period in 2000. Other income decreased 24.3 percent or \$0.4 million for the six months ended June 30, 2001, compared with the same period in 2000 due primarily to a favorable settlement of a claim in the first quarter of 2000 and reductions in interest income during 2001 due to lower temporary cash investments.

### INTEREST CHARGES

Interest charges increased 1.3 percent or \$23,000 in the second quarter of 2001 compared with the same period in 2000 primarily due to increased costs associated with the revolving lines of credit discussed under "Liquidity and

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Capital Resources", offset in part by reductions in interest on long-term debt due to sinking fund redemption.

Interest charges increased 6.3 percent or \$0.2 million for the six months ended June 30, 2001 compared with the same period in 2000 for the same reason.

### LIQUIDITY AND CAPITAL RESOURCES

In the three months ended June 30, 2001, we spent \$5.7 million principally for expansion and improvements of our transmission and distribution plant. We expect to spend an additional \$10.0 million during the remainder of 2001.

On June 20, 2001, we renewed a revolving credit agreement (the "Fleet Agreement") with Fleet National Bank ("Fleet"), joined by KeyBank National Association ("KeyBank"). The Fleet Agreement is for a period of 364 days, will expire on June 19, 2002, and is unsecured. We had \$4.9 million in borrowings outstanding on the Fleet Agreement at June 30, 2001.

On September 20, 2000, we established a \$15.0 million revolving credit agreement with KeyBank (the "KeyBank Agreement") which will expire on September 19, 2001. Pursuant to a one year power supply option agreement between the Company and Energy East Corporation ("EE"), EE made a payment of \$15.0 million to the Company. In exchange, the Company gave EE an option to purchase energy from certain wholly owned production facilities, for a period not to exceed 15 years, if the funds are not returned to EE. The Company was required to invest the funds provided by EE in a certificate of deposit at KeyBank pledged by the Company to secure the repayment of loans made pursuant to the KeyBank Agreement. At June 30, 2001, there were no amounts outstanding on the KeyBank Agreement.

On June 20, 2001, the Company executed and delivered a \$12.0 million two-year loan agreement with Fleet, joined by KeyBank. Funding of this facility was contingent upon VPSB approval. On July 27, 2001 the VPSB approved the financing arrangement. The Company plans to use this facility to terminate the KeyBank Agreement, and repay the \$15.0 million it received from EE pursuant to a power supply option agreement as soon as is practicable.

The credit ratings of the Company's securities are:

	Fitch	Moody's	Standard & Poor's
	-----	-----	-----
First mortgage bonds	BBB	Baa2	BBB
Preferred stock	BBB-	Ba2	BB

### COMPETITION AND RESTRUCTURING

The electric utility business is experiencing rapid and substantial changes. These changes are the result of the following trends:

- \* Disparity in electric rates, transmission, and generation capacity among and within various regions of the country;
- \* Improvements in generation efficiency;
- \* Alternative energy sources;
- \* The deregulation of the wholesale energy market and the establishment of an independent system operator; and
- \* New regulations and legislation in some states intended to foster competition, also known as restructuring.

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.

### NUCLEAR DECOMMISSIONING

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The staff of the SEC has questioned certain current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating units in financial statements. In response to these questions, the Financial Accounting Standards Board ("FASB") had agreed to review the accounting for closure and removal costs, including decommissioning. The FASB is expected to issue a new statement on accounting standards in August 2001 for "Accounting for the Impairment or Disposal of Long-lived Assets and for Obligations Associated with Disposal Activities", which will provide guidance on accounting for nuclear plant decommissioning costs. The Company has not yet determined what impact, if any, the proposed accounting standard will have on its investment in VY.

### EFFECTS OF INFLATION

Financial statements are prepared in accordance with generally accepted accounting principles and report operating results in terms of historic costs. This method of accounting provides reasonable financial statements but does not always take inflation into consideration. As rate recovery is based on these historical costs and known and measurable changes, the Company is able to receive some rate relief for inflation. It does not receive immediate rate recovery relating to fixed costs associated with Company assets. Such fixed costs are recovered based on historic figures. Any effects of inflation on plant costs are generally offset by the fact that these assets are financed through long-term debt.

### MARKET RISK

In June 1998, the FASB issued Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities. SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in 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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133, as amended by SFAS 137, is effective for the Company beginning the first quarter of 2001. SFAS 133 must be applied to (a) derivative instruments and (b) either all derivative instruments embedded in hybrid contracts or those embedded instruments that were issued, acquired, or substantively modified on or after January 1, 1998 or January 1, 1999 (as elected by the Company).

The objective of the Company's risk management program is to protect cash flow and earnings by minimizing risk. Permitted transactions 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 risk of fossil fuel price increases as well as the risk of spot market electricity price increases. Futures, swaps and forward contracts are used to hedge the impact of market prices on the Company should option calls by Hydro-Quebec be exercised by Hydro-Quebec. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and limits to transaction authority.

A sensitivity analysis has been prepared to estimate the exposure to the market price risk of our electricity commodity positions. Our daily net commodity position consists of purchased electric capacity. The table below presents market risk, estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in prices. Actual prices may differ materially from the table.

At June 30, 2001

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	Fair value -----		Market risk -----
(in thousands)			
Highest long position	\$	26,205	\$ 2,621
Highest short position	\$	43,180	\$ 4,318
Average position(short)	\$	(16,975)	\$ (1,698)

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GREEN MOUNTAIN POWER CORPORATION  
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JUNE 30, 2001  
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PART II - OTHER INFORMATION  
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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 17, 2001, one item was 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.

Nordahl L. Brue, votes for, 4,713,579; withheld authority, 70,201; abstentions, 799,937.

Lorraine E. Chickering, votes for, 4,687,768; withheld authority, 96,012; abstentions, 799,937.

John V. Cleary, votes for, 4,698,695; withheld authority, 85,085; abstentions, 799,937.

Euclid A. Irving, votes for, 4,683,381; withheld authority, 100,399; abstentions, 799,937.

Directors continuing in office were Merrill O. Burns, William Bruett, David R. Coates, Christopher L. Dutton, and Thomas P. Salmon.

ITEM 5. Other Information  
NONE

ITEM 6. (B) REPORTS ON FORM 8-K  
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None

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GREEN MOUNTAIN POWER CORPORATION  
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SIGNATURES  
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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  
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(Registrant)

Date: August 10, 2001            /s/Nancy Rowden Brock  
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Nancy Rowden Brock, Vice President,  
Chief Financial Officer, Secretary,  
and Treasurer

Date: August 10, 2001            /s/Nancy Rowden Brock  
-----

Officer)  
Nancy Rowden Brock, (as Principal Financial  
Vice President, Chief Financial Officer,  
Secretary, and Treasurer