GREEN MOUNTAIN POWER CORPORATION

Annual Report to Shareholders

2001

Improving customer satisfaction and shareholder confidence in ten not-so-easy steps

Financial and Operating Highlights

	2001	2000	1999
Financial Data			
Operating revenues	**$283,464,000**	$277,326,000	$251,048,000
Operating expenses	**$267,005,000**	$272,066,000	$243,102,000
Net income (loss), continuing operations	**$ 10,860,000**	($ 305,000)	3,061,000
Net income (loss), discontinued operations	**($ 182,000)**	($ 6,549,000)	($ 7,279,000)
Net income (loss) applicable to common stock	**$ 10,678,000**	($ 6,854,000)	($ 4,218,000)
Total utility plant	**$309,953,000**	$298,496,000	$288,711,000
Common Share Data			
Weighted average shares outstanding	**5,630,000**	5,491,000	5,361,000
Year-end shares outstanding	**5,685,000**	5,567,000	5,410,000
Basic earnings (loss) per average share, continuing operations	**$ 1.93**	($ 0.06)	$ 0.57
Basic earnings (loss) per average share, discontinued operations	**($ 0.03)**	($ 1.19)	($ 1.36)
Basic earnings (loss) per average share	**$ 1.90**	($ 1.25)	($ 0.79)
Dividends paid per share	**$ 0.55**	$ 0.55	$ 0.55
Year-end book value per share	**$17.81**	$16.53	$18.60
Dividend yield on ending market value	**2.95%**	4.40%	7.39%
Return on average common equity	**11.02%**	–7.10%	–4.00%
Operating Data			
Electric customers—year-end	**87,000**	86,000	84,000
Retail and requirements sales (MWH)	**1,956,000**	1,955,000	1,920,000
Other sales for resale (MWH)	**2,365,000**	2,574,000	2,153,000
Average revenue per kWH (cents)	**10.44**	9.52	9.47
Number of Employees—Year-End			
Green Mountain Power	**193**	197	196
Subsidiaries	**0**	5	5

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It is the policy of Green Mountain Power to provide equal employment opportunities to all qualified employees and applicants. Through its affirmative action plan and affirmative action efforts, GMP ensures that the policy is enforced.

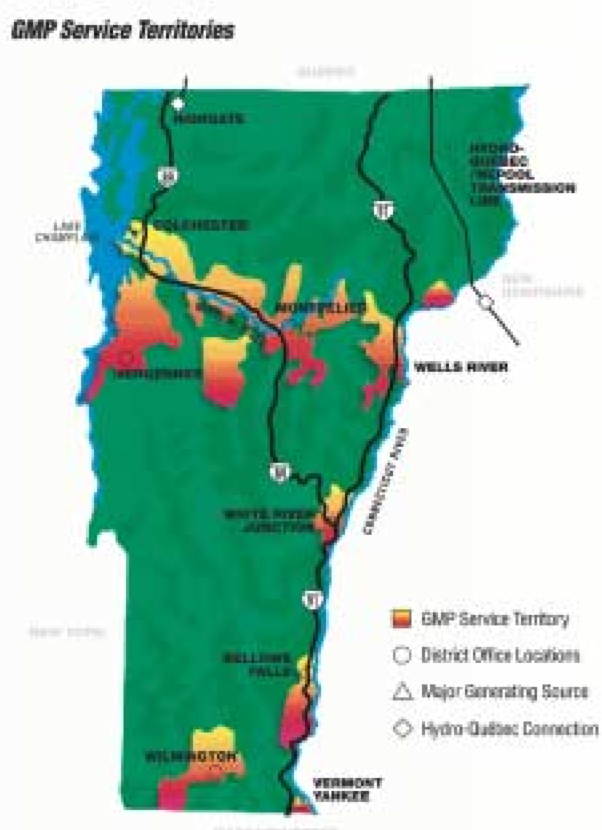
Dear Green Mountain Power shareholder:

GREEN MOUNTAIN POWER'S operating results for 2001 were as satisfying as we had hoped they would be when we reported to you last year:

- The return on common equity for core operations was 11.25 percent, the target established by the Vermont Public Service Board to be a fair return for Green Mountain Power shareholders.
- Consolidated earnings per share were $1.85, up from a loss of $1.25 per share in 2000.
- The year-end price of Green Mountain Power stock was $18.65 per share, a gain of nearly 50 percent from the $12.50 per share price on January 1, 2001, producing a price-to-earnings ratio of 10.
- Customer satisfaction was 90 percent, a gain of five percent from the previous year.
- Productivity, as measured by Green Mountain Power's customer-to-employee ratio of 454 to one, was among the highest in the electric utility industry.
- The credit rating agencies restored Green Mountain Power's investment-grade ranking and set our outlook as "positive."

But the numbers tell only part of the developing story of Green Mountain Power. The employees of your Company have done no less than reinvent the way we do business. Recognizing that satisfied customers are essential for financial success, we have a laser focus on responding to customer needs, and we are using new technology to do it faster, smarter and more efficiently than ever before. We've developed innovative ways to help our customers over the web, while incorporating satellite computer technology to assist lineworkers in responding quickly during outages and providing the reliable service our customers demand. We've even offered money-back guarantees on some of our services. In short, we expect to wow our customers with our service. Here's how:

The employees of your Company have done no less than reinvent the way we do business. Recognizing that satisfied customers are essential for financial success, we have a laser focus on responding to customer needs, and we are using new technology to do it faster, smarter and more efficiently than ever before.



Our sophisticated computer technology improves reliability.

MORE THAN HALF of our customers believe reliability is the most important quality for an electric utility. No other measure of service, including price, is even half that important to our customers. We have deployed very sophisticated technology to make sure we respond quickly to any interruptions on our system.

Every piece of electrical equipment we own has been surveyed and mapped with the Global Positioning System (GPS). Combining a Geographic Information System (GIS) with the GPS, we have created a powerful tool to track information and respond to customers. Our lineworkers now have laptop computers in their trucks to bring them information, including extremely accurate maps, actual pictures of poles and transformers, and spreadsheets of technical information about every piece of equipment on our system. The GIS/GPS system radically improves both the quality and quantity of information available to us during outages, which significantly cuts our time in responding. In line with our focus on efficiency, the GIS/GPS program reduces paper work and streamlines prep work for jobs, allowing lineworkers to spend more time in the field actually accomplishing their mission.

Further developments in the GIS/GPS system enable us to track outages as they occur. The moment a customer calls to tell us about an outage, a report is automatically updated to track the outage, crew dispatchers are automatically notified, and our electronic maps show that the customer has lost service. We can now analyze more accurately the extent of any storm damage and prepare a faster, more efficient response, including giving customers an estimated restoration time.

Busy signals are a relic of the past.

WHEN CUSTOMERS CALL, they want an answer quickly. Often they can find out what they need from our interactive voice system. Other times, they need to speak with us. Our call center performance has improved steadily. Most of our calls are answered within 30 seconds. There are times during power outages when the number of telephone lines coming into our offices cannot possibly accommodate the thousands of customers trying to call us. So that those customers are not met with a frustrating busy signal when they need to tell us that their power is out, we have contracted with an outside automated service to take all overflow calls. The connection is seamless for the customer, who can receive essential information or report the outage and hang up, knowing we will take care of the problem.

Green Mountain Power lineworkers Steve Caldwell and Steve Bolduc use our new GIS/GPS information technology system to check the circuit maps during an outage. Immediate access to up-to-date maps, work schedule and system information helps us respond faster and more efficiently.

Customers can access their accounts over our web site.

TODAY'S CONSUMER EXPECTS to get information over the web. We know that 70 percent of our customers have access to the Internet, either at home or at work. In late 2001, we created a new Internet web site for Green Mountain Power, greenmountainpower.biz. We wanted a site that was customer focused and easy to use. If customers want to check a bill amount, see if their payment was received, or even adjust an estimated bill amount, they can now do it 24 hours a day over the web. Our web site gives them more flexibility and greater access to information than they have ever had from a utility.

We offer* My Home, *an interactive web vehicle to help customers improve their understanding of electricity usage.

WHILE WE REDEVELOPED our web site, we also set out to build a fun way for our customers to understand their own usage patterns and how their consumption relates to their bill. The result was *My Home*, a unique web device that gives customers unprecedented appreciation of how they use electricity and how much they pay for it. Customers can do a simple layout of their home, add the appliances they use every month, and *My Home* calculates their usage and compares it to their most recent bill. It is easy to see which appliances use the most electricity, so customers can learn exactly how their usage habits affect their bills. We are seeking a patent on this technology, which was an instant success in Vermont, and other electric companies around the country have expressed an interest in *My Home*.

With *My Home*, our unique web device, customers can do a simple layout of their home, add the appliances they use every month, and calculate their usage and compare it to their most recent bill.

Chrissie Drescher, a customer in Hinesburg, Vermont, uses the new My Home *feature on the Green Mountain Power web site to learn more about her family's electricity consumption.*

We have a stable power supply for the future.

THROUGH OUR ARRANGEMENTS with Morgan Stanley, 95 percent of our power supply is essentially "hedged" through 2003 against extreme market price conditions. We have a diverse portfolio of sources that are unusually low in emissions. More than 40 percent of the energy we delivered in 2001 came from renewable sources, an environmental benefit that is valued highly in Vermont. In addition to our own hydro and wind plants, we have a long term contract with Hydro Quebec that provides a steady source of reliable and clean power until 2015. One major power supply issue remains unresolved: Green Mountain Power and the other joint owners of the Vermont Yankee nuclear power plant in August 2001 agreed to sell the plant to Entergy Corporation. The Federal Energy Regulatory Commission has approved the sale.

Green Mountain Power and the other Vermont owners believe that Vermont Yankee's sponsor utilities, their customers, and the State of Vermont would benefit from the sale. Further, the price of the power that we will purchase from the plant and the other terms of the power sales contracts should provide significant benefits and protections to our customers. Most importantly, though, the proposed sale would relieve Green Mountain Power and Vermont of many of the financial uncertainties associated with the nuclear plant. In addition, although Vermont Yankee continues to be one of the best performing nuclear plants in the nation, and in fact has set records for operating efficiency, the risks involved in plant relicensing, safety, and fuel waste disposal are more appropriate for a larger energy company with extensive nuclear holdings. Entergy, which was the top bidder for Vermont Yankee in an auction process, owns nine other nuclear units, including four in the Northeast.

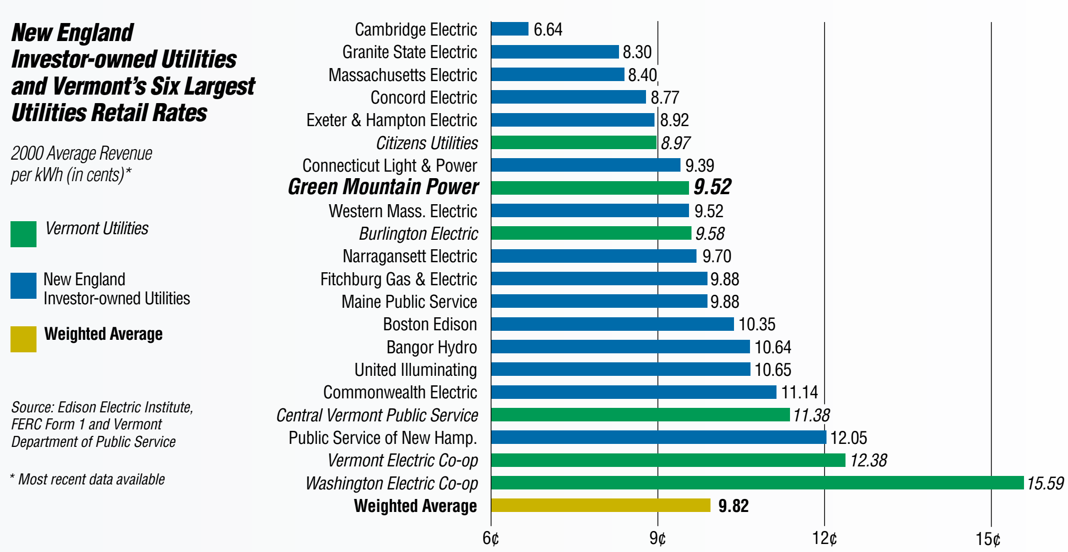
Under the proposed sale, we and the other owners would continue to receive the same allotment of the nuclear plant's power production to which we are now entitled through 2012, the year Vermont Yankee's current license is scheduled to expire, but at a reduced cost. The Vermont Public Service Board will rule on the proposed Vermont Yankee sale by July 31, 2002.

Power Supply Costs by Source

Source	2001 Cents per kWh
Average all sources	5.7
Nuclear	4.3
Market purchases	4.7
GMP hydro	5.3
Oil and gas	5.5
Hydro-Québec	6.3
Wind	7.0
Qualifying facilities	11.7

Our rates are competitive in the region.

GREEN MOUNTAIN POWER'S retail rates continue to be among the lowest in Vermont, below the average for New England, and declining in comparison with both markets. We agreed, as part of our 2000 rate case settlement, not to raise rates before January 2003, unless certain substantially adverse conditions arise.



GMP's Energy Sources 2001

Hydro:	
Hydro-Québec	33.2%
NYPA	0.1
GMP Owned	2.4
	35.7
Nuclear:	
Vermont Yankee	30.8
Market Purchases:	23.9
Qualifying Facilities:	
Hydro	1.7
Ryegate (wood)	2.4
	4.1
Natural Gas:	
MMWEC	2.1
McNeil	0.1
	2.2
Oil:	
Wyman	0.3
GT&D	0.8
MMWEC	0.9
	2.0
Wood:	
McNeil	0.8
Wind:	
Searsburg	0.5
TOTAL	100.0%

Our goal is to set and then meet performance standards that will place Green Mountain Power firmly in first place as New England's best-performing electric utility.

Our new service quality standards address customer needs.

CUSTOMERS EXPECT high quality performance, especially when it comes to reliability and answering the phone. Working with state regulators, we developed a set of performance and reliability standards in critical areas. We monitor and report how quickly we answer the phone, how often and how long power is interrupted, how accurately we read meters and how satisfied our customers are. In the first year, we met most standards, and for the few places where we missed the mark, we developed aggressive remediation plans.

Our goal is to set and then meet performance standards that will place Green Mountain Power firmly in first place as New England's best-performing electric utility. We believe that is an attainable objective, made possible by a trained and dedicated workforce equipped with the best technology and led by a deft, adaptable and hard-working management team.

We back up our promises with money-back guarantees.

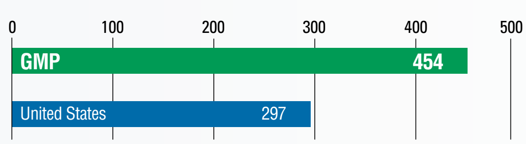
WE PUT OUR MONEY where our mouth is. When we implemented our service quality standards, we also announced New England's first money-back guarantee for electric customers. If Green Mountain Power fails to meet announced standards in certain service areas, we give customers a rebate on their monthly bills. We began the guarantees in mid-2001, and decided we wanted to challenge ourselves to respond even faster and better. So in early 2002, we toughened those standards, significantly reducing the time we allow for installing new service, for installing temporary service, and for service connections at construction sites. We believe raising the bar for how quickly we deliver our service is an important way to show customers we are committed to continuing to improve customer service, safety and reliability.

Our workforce is efficient, motivated and skilled.

WE CONTINUED to refine and redefine our work processes in 2001, using technology to centralize certain functions and at the same time flatten out supervisory structures. For now, at least, the overall size of the workforce has stabilized at about 190 active employees, or one employee for every 454 customers, one of the highest such ratios in the entire country for a stand-alone electric utility.

We have consolidated all work (except hands-on repair, construction and maintenance on the distribution and generation systems, and meter reading) in a central location at the Company's service building in Colchester. In 2001, the engineering and call center operations were moved into space freed up by earlier consolidation and job reductions. These moves, besides saving money, have improved communication and cooperation among various departments and have improved many customer service functions. Green Mountain Power continues to serve customers in five non-contiguous geographical areas of Vermont, but technology has made possible a consolidation and trimming of workforce that would have been impossible a few years ago.

Customers Served per Employee



Investor-owned utilities only. Source: Edison Electric Institute.
Most recent data available: US 2000, GMP 2001

For customers, the bottom line in all these changes is better, more efficient service. We are able to reduce the number and duration of outages, respond faster to emergencies, and constantly improve the distribution system. And we're able to do it with fewer people.

The smarter–faster pattern for work has not been restricted to certain functional levels of the Company, though. Every organizational level has been consolidated, including senior management. Five years ago we had twelve senior officers; now we have four.

We have achieved bedrock financial stability, which is necessary to support innovations for customers and to satisfy shareholders.

THE NUMBERS at the beginning of this letter demonstrate conclusively that Green Mountain Power performed well for shareholders in 2001. The financial stability that we have achieved is essential for us to pursue innovative ways to provide excellent service to our customers. At the same time, it is not possible to meet our obligations to shareholders unless we also please our customers. Customer focus and shareholder value cannot be separated.

Regardless how soon and how strongly the national economy resumes its growth, it now appears unlikely that Vermont will soon join the trend toward retail competition in the electric industry. At Green Mountain Power, we are operating as a company that will continue to provide all the traditional functions of an electric utility. We do not intend, however, to function traditionally. With the enthusiastic support of our people and the understanding and encouragement of State regulators, we expect to work as nimbly as any entrepreneur. We will exploit the latest technologies and employ the brightest minds.

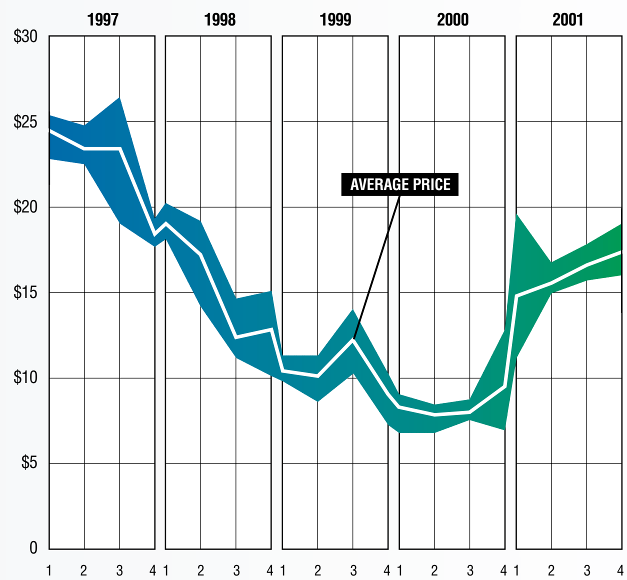
We will be vigilant in seeking new ways to earn money for shareholders and equally eager to find new and better ways to serve customers.

Thomas P. Salmon
Chairman

Christopher L. Dutton
President and Chief Executive Officer

March 6, 2002

Quarterly Stock Market Price Data



2001 ending stock price was $18.65.

Green Mountain Power Corporation common stock is traded on the New York Stock Exchange (NYSE symbol: GMP). This chart shows the high and low closing prices for the Company's common stock for each quarter from 1997 through 2001, as reported by the New York Stock Exchange. The number of registered shareholders of common stock as of December 31, 2001 was 5,746.

		Stock Price High	Stock Price Low	Dividend Declared
2001	First Quarter	$19.50	$11.0625	13.75¢
	Second Quarter	16.65	14.88	13.75
	Third Quarter	17.74	15.56	13.75
	Fourth Quarter	18.85	15.90	13.75
2000	First Quarter	$ 8.9375	$ 6.813	13.75¢
	Second Quarter	8.4375	6.75	13.75
	Third Quarter	8.69	7.50	13.75
	Fourth Quarter	12.81	6.88	13.75

Board of Directors

Thomas P. Salmon, 69, elected 1978, Chairman of the Board, GMP; retired President of the University of Vermont. Of Counsel, Salmon & Nostrand, Attorneys; former Governor of Vermont; Rockingham, Vermont.

Nordahl L. Brue, 57, elected 1992, Chairman and Chief Executive Officer of Bruegger's Corporation; Principal, Champlain Management Services, Inc.; Burlington, Vermont.

William H. Bruett, 58, elected 1986, former Senior Vice President, Group Product Manager of PaineWebber, Inc., Director of PaineWebber Trust Co. and Chairman of PaineWebber International Bank Ltd., London; Weehawken, New Jersey.

Merrill O. Burns, 55, elected 1988, former Group Executive, MarchFirst (Internet Professional Services); San Francisco, California.

Lorraine E. Chickering, 51, elected 1994, former President of Public Communications of Bell Atlantic Corporation; Silver Springs, Maryland.

John V. Cleary, 73, elected 1980, retired President and Chief Executive Officer, GMP; Boynton Beach, Florida.

David R. Coates, 64, elected 1999, retired Partner, KPMG Peat Marwick; Burlington, Vermont.

Christopher L. Dutton, 53, elected 1997, President, Chief Executive Officer and Chairman of the Executive Committee of GMP; Colchester, Vermont.

Euclid A. Irving, 49, elected 1993, Partner, Paul, Hastings, Janofsky & Walker, LLP, Attorneys; New York, New York.

Officers

Christopher L. Dutton
President and Chief Executive Officer

Robert J. Griffin
Controller and Treasurer

Walter S. Oakes
Vice President, Field Operations

Mary G. Powell
Senior Vice President and Chief Operating Officer

Stephen C. Terry
Senior Vice President, Corporate and Legal Affairs

Board of Directors Committees

Audit Committee
Euclid A. Irving, Chair
William H. Bruett
Merrill O. Burns
David R. Coates

Compensation Committee
Merrill O. Burns, Chair
Lorraine E. Chickering
John V. Cleary
David R. Coates
Euclid A. Irving

Executive Committee
Christopher L. Dutton, Chair
Nordahl L. Brue
David R. Coates
Thomas P. Salmon

Governance Committee
William H. Bruett, Chair
Nordahl L. Brue
Lorraine E. Chickering
John V. Cleary
Thomas P. Salmon

Elizabeth A. Bankowski nominated to Green Mountain Power Board

Elizabeth A. Bankowski, 54, a business consultant in the area of corporate social responsibility, has been nominated for election to Green Mountain Power's Board of Directors at the May 2002 Annual Meeting. She was a Senior Director at Ben & Jerry's Homemade Inc. from 1991 until June 2001 and remains a trustee of the Ben & Jerry's Foundation. From 1985 to 1990, she served as Chief-of-Staff for Vermont Governor Madeleine M. Kunin, whose successful campaign she ran in 1984. In 1992, she served on President Clinton's Transition Team, advising on economic issues. We welcome the talents and insight she will bring to Green Mountain Power's Board. Ms. Bankowski lives in Brattleboro, Vermont.

Thomas P. Salmon retires from Board

Thomas P. Salmon, Chairman of the Board of Directors and one of the architects of the modern Green Mountain Power, is retiring after nearly a quarter-century of service. He will leave the Board of Directors after its regular May meeting when a new chairman will be elected.

Mr. Salmon, 69, came to the Green Mountain Power Board in 1978 fresh from two terms as Governor of Vermont. In 1983, he was elected Chairman and was instrumental in a management reorganization that, over the next several years, brought fundamental changes in the Company and a period of unparalleled success.

In 1991, while serving as Chairman, Mr. Salmon was called back into public service as President of the University of Vermont. He served nearly six years in that post and was largely responsible for rebuilding bonds of mutual respect between the university and its core constituencies, the Legislature and the people of the state.

In his "years before the mast," to use one of Mr. Salmon's own characteristic metaphors, he brought to State government, to the University of Vermont and to Green Mountain Power a steadfast dedication that was never questioned. He also set the standard in every venture that he undertook for dawn-to-dark work and indefatigable energy.

Throughout his tenure as Chairman, Mr. Salmon's training as a lawyer, his experience as a judge, as a legislator, as a chief executive, and as a political and business leader were abiding assets for Green Mountain Power. He will be missed by the Company.

Christopher L. Dutton

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 explanation includes:

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

There are statements in this section that contain projections or estimates and that are considered to be "forward-looking" as defined by the Securities and Exchange Commission (the "SEC"). In these statements, you may find words such as believes, expects, plans, or similar words. These statements are not guarantees of our future performance. There are risks, uncertainties and other factors that could cause actual results to be different from those projected. Some of the reasons the results may be different are discussed under the captions "Future Outlook", "Transmission Expenses", "Environmental Matters", "Rates" and "Liquidity and Capital Resources", in this Management Discussion and Analysis and include:

- regulatory and judicial decisions or legislation;
- weather;
- energy supply and demand and pricing;
- contractual commitments;
- availability, terms, and use of capital;
- general economic and business environment;
- changes in technology;
- nuclear and environmental issues; and
- industry restructuring and cost recovery (including stranded costs).

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

Earnings Summary

The Company reported consolidated earnings of $1.85 per share of common stock, diluted, in 2001 compared to a loss of $1.25 per share in 2000 and a loss of $0.79 per share in 1999. The 2001 earnings represent a consolidated return on average common equity of 11.02 percent, and a return on regulated operations of 11.25 percent. The consolidated return on average common equity was negative 7.1 percent in 2000 and negative 4.0 percent in 1999. Income from continuing operations was $1.88 per share, diluted, in 2001, compared with a loss of $0.06 per share in 2000 and earnings of $0.57 per share in 1999. Certain subsidiary operations, classified as discontinued in 1999, lost $0.03 per share in 2001, compared with a loss of $1.19 per share in 2000 and a loss of $1.36 per share in 1999.

On January 23, 2001, the Vermont Public Service Board ("VPSB") issued an order (the "Settlement Order") approving a settlement between the Company and the Vermont Department of Public Service (the "Department") that granted the Company an immediate 3.42 percent rate increase, and allowed full recovery of power supply costs under the Hydro-Québec Vermont Joint Owners ("VJO") contract. The Settlement Order paved the way for restoration of the Company's first mortgage bond credit rating to investment grade status (See "Retail Rate Cases" and "Liquidity and Capital Resources" in this section) and along with lower power supply costs, enabled the Company to earn its allowed rate of return of 11.25 percent on utility operations during 2001.

The improvement in earnings from continuing operations in 2001 compared with the prior year resulted from several factors, primarily:

- power supply costs were $10.5 million lower than during 2000, principally due to decreased costs associated with the management of the Company's long-term power supply sale commitments to Hydro Quebec, and a decrease in lower margin wholesale sales of electricity;
- the 3.42 percent retail rate increase under the Settlement Order resulted in an increase of $9.1 million in retail operating revenues; and
- the write-off in 2000 of $3.2 million or $0.35 per share in regulatory litigation costs.

The consolidated loss in 2000 was greater than the prior year consolidated loss as a result of the VPSB Settlement Order that provided for the write-off of $3.2 million or $0.35 per share in regulatory litigation costs and higher power supply costs that were not recovered in rates. Power supply expense increased $28.3 million in 2000, outpacing revenue growth of $26.3 million and reductions in depreciation and amortization expense of $0.9 million.

The Company's discontinued operations lost $0.03 per share in 2001, compared with a loss of $1.19 per share in 2000, and a loss of $1.36 per share in 1999. During 1999, the Company discontinued operations of Northern Water Resources, Inc. ("NWR"), formerly known as Mountain Energy, Inc., a subsidiary of the Company that invested in wastewater, energy efficiency and generation businesses. The loss in 2000 reflects the sale of most of NWR's remaining energy assets and the estimated costs of winding down NWR's wastewater businesses.

Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors—The primary concern affecting future operating results is the volatility of the wholesale electricity market. Inherent in our market risk sensitive instruments and positions is the potential loss arising from adverse changes in our commodity prices. Restructuring of the wholesale market for electricity has brought increased price volatility to our power supply markets.

The price of electricity is subject to fluctuations resulting from changes in supply and demand. To reduce price risk caused by these market fluctuations, we have established a policy to hedge (through the utilization of derivatives) our supply and related purchase and sales commitments, as well as our anticipated purchases and sales. Changes in the market value of derivatives have a high correlation to the price changes of the hedged commodities.

The Company has a contract with Morgan Stanley Capital Group, Inc. ("MS"), which is 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 Statement of Financial Accounting Standards Number 133 ("SFAS 133") and is effective through December 31, 2003. Management's estimate of the fair value of the future net cost of this arrangement at December 31, 2001 is approximately $11.6 million.

We also sometimes use future contracts to hedge forecasted wholesale sales of electric power, including material sales commitments as discussed in Note K. We currently have an arrangement with Hydro-Québec that grants them an option to call power at prices that may be 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 December 31, 2001 is approximately $25.7 million.

A sensitivity analysis has been prepared to estimate the exposure to the market price risk of our electricity commodity positions, using the Black-Scholes model, over the next 13 years. Our daily net commodity position consists of purchased electric capacity. Assumptions used within the model include a ten-year government bond risk-free interest rate of 5.02 percent, volatility equivalent to the peer weighted average from NEPOOL which varies from 36 percent in the first year to 18 percent in year 13, locked in forward commitment prices for 2002 and 2003, and an average of approximately 71,500 MWh per year with a forward market price of $54.29 per MWh for periods beyond 2003. Actual results may differ materially from the table. 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. 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 $1.8 million.

Commodity Price Risk	At December 31, 2001	
	Fair Value	Market Risk
	(In thousands)	
Net short position	$37,313	$1,789

The major risk factors for the Company arising from electric industry restructuring, including risks pertaining to the recovery of stranded costs, are:

- regulatory and legal decisions;
- cost and amount of default service responsibility;
- the market price of power; and
- the amount of market share retained by the Company.

There can be no assurance that any potential future restructuring plan ordered by the VPSB, the courts, or through legislation will include a mechanism that would allow for full recovery of our stranded costs and include a fair return on those costs as they are being recovered. If laws are enacted or regulatory decisions are made that do not offer an adequate opportunity to recover stranded costs, we believe we have compelling legal arguments to challenge such laws or decisions.

The largest category of our potential stranded costs is future costs under long-term power purchase contracts, which, based on current forecasts, are above-market. The magnitude of our stranded costs is largely dependent upon the future market price of power. We have discussed various market price scenarios with interested parties for the purpose of identifying stranded costs. Preliminary market price assumptions, which are likely to change, have resulted in estimates of the Company's stranded costs of between $167 million and $204 million over the life of the contracts. We intend to aggressively pursue mitigation efforts in order to minimize the amount and maximize the recovery of these costs.

If retail competition is implemented in Vermont, we cannot predict what the impact would be on the Company's revenues from electricity sales. Historically, electric utility rates have been based on a utility's cost of service. As a result, electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards Number 71, ("SFAS 71"), Accounting for the Effects of Certain Types of Regulation, allows regulated entities, in appropriate circumstances, to establish regulatory assets and liabilities, and thereby defer the income statement impact of certain costs and revenues that are expected to be realized in future rates.

The Company currently complies with the provisions of SFAS 71. In the event the Company determines that it no longer meets the criteria for following SFAS 71, the accounting impact would be an extraordinary, non-cash charge to operations of $74.2 million. Factors that could give rise to the discontinuance of SFAS 71 include:

- deregulation;
- a change in the regulators' approach to setting rates from cost-based regulation to another form of regulation;
- increasing competition that limits our ability to sell utility services or products at rates that will recover costs; and
- regulatory actions that limit rate relief to a level insufficient to recover costs.

The enactment of restructuring legislation or issuance of a regulatory order containing provisions that do not allow for the recovery of above-market power costs would require the Company to estimate and record losses immediately, on an undiscounted basis, for any above-market power purchase contracts and other costs which are probable of not being recoverable from customers, to the extent that those costs are estimable.

We are unable to predict what form future legislation, if passed, or an order if issued, will take, and we cannot predict if or to what extent SFAS 71 will continue to be applicable in the future. In addition, members of the staff of the Securities and Exchange Commission have raised questions concerning the continued applicability of SFAS 71 to certain other electric utilities facing restructuring. However, we currently believe that the continued application of SFAS 71 is appropriate at this time.

We cannot predict whether restructuring legislation enacted by the Vermont General Assembly or any subsequent report or actions of, or proceedings before, the VPSB or the Vermont General Assembly would have a material adverse effect on our operations, financial condition or credit ratings. The failure to recover a significant portion of our purchased power costs, or to retain and attract customers in a competitive environment, would likely have a material adverse effect on our business, including our operating results, cash flows and ability to pay dividends at current levels.

Unregulated Businesses

In 2000, we significantly reduced our investment in unregulated businesses, continuing the process we began in June 1999, when we decided to sell or otherwise dispose of the assets of NWR, and report its results as loss from operations of a discontinued segment. NWR, which invested in energy generation, energy efficiency and wastewater treatment projects, lost approximately $0.2 million in 2001, compared with a loss of $6.5 million in 2000, and a loss of $7.3 million in 1999. The 2001 loss resulted primarily from provisions to recognize adjustments to liability estimates under warrantees for past equipment sales.

Risk factors associated with the discontinuation of NWR operations include the outcome of warranty litigation, and future cash requirements necessary to minimize costs of winding down wastewater operations. Several municipalities using wastewater treatment equipment provided by Micronair, LLC, a wholly owned subsidiary of NWR, have commenced or threatened litigation against Micronair. The ultimate loss remains subject to the disposition of remaining NWR assets and liabilities, and could exceed the amounts recorded.

The Company's unregulated rental water heater business earned $0.3 million in 2001, essentially unchanged from the prior year.

Results of Operations

Operating Revenues and MWh Sales—Operating revenues and megawatthour ("MWh") sales for the years ended 2001, 2000 and 1999 consisted of:

	Years ended December 31, 2001	2000	1999
	(Dollars in thousands)		
Operating Revenues:			
Retail	$195,093	$185,944	$179,997
Sales for Resale	83,804	88,333	68,305
Other	4,567	3,049	2,746
Total Operating Revenues	$283,464	$277,326	$251,048
MWH Sales—Retail	1,948,131	1,947,857	1,900,188
MWH Sales for Resale	2,368,887	2,575,657	2,172,849
Total MWH Sales	4,317,018	4,523,514	4,073,037

Average Number of Customers

	Years ended December 31, 2001	2000	1999
Residential	73,270	72,424	71,515
Commercial and Industrial	13,006	12,769	12,461
Other	65	65	66
Total Number of Customers	86,341	85,258	84,042

Differences in operating revenues were due to changes in the following:

Change in Operating Revenues	2000 to 2001	1999 to 2000
	(In thousands)	
Retail Rates	$ 9,122	$ 4,551
Retail Sales Volume	27	1,396
Resales and Other Revenues	(3,011)	20,331
Increase in Operating Revenues	$ 6,138	$26,278

In 2001, total electricity sales decreased 4.6 percent compared with 2000 due principally to reduced sales for resale executed pursuant to the MS agreement, described in more detail below under the headings "Power Supply Expenses" and "Power Contract Commitments". Total operating revenues increased $6.1 million or 2.2 percent in 2001 compared with 2000 primarily due to increases in retail and other operating revenues, partially offset by a decrease in lower margin wholesale sales. Retail operating revenues increased $9.1 million or 4.9 percent in 2001 compared with 2000 due to a 3.42 percent retail rate increase that went into effect January 2001 and an additional increase in revenues from an industrial customer pursuant to revisions in a special contract with that customer approved in the Settlement Order.

In 2000 total electricity sales increased 11.1 percent compared with 1999 due principally to sales for resale executed pursuant to the MS agreement, described in more detail below under the headings "Power Supply Expenses" and "Power Contract Commitments". Total operating revenues increased $26.3 million or 10.5 percent primarily for the same reason. Total retail revenues increased $5.9 million or 3.3 percent in 2000 primarily due to:

- a 3.0 percent retail rate increase that went into effect January 2000; and
- a 2.6 percent increase in sales of electricity to both our commercial and industrial and our residential customers resulting primarily from customer growth and load growth for our largest customer.

International Business Machines ("IBM"), the Company's single largest customer, operates manufacturing facilities in Essex Junction, Vermont. IBM's electricity requirements for its main plant and an adjacent plant accounted for approximately 26.6, 26.6, and 25.9 percent of the Company's retail MWh sales in 2001, 2000, and 1999, respectively, and 19.2, 16.5, and 16.2 percent of the Company's retail operating revenues in 2001, 2000, and 1999, respectively. No other retail customer accounted for more than one percent of the Company's revenue in any year.

Since 1995, the Company has had agreements with IBM with respect to electricity sales above agreed-upon base-load levels. On December 8, 2000, the VPSB approved a new three-year agreement between the Company and IBM, ending December 31, 2003. The price of power for the renewal period of the agreement is above our marginal costs of providing incremental service to IBM.

Power Supply Expenses—Prior to 2001, our inability to recover our power supply costs had been a primary reason for the poor performance of the Company's common stock price during 1999 and 2000. The Settlement Order removed this obstacle by allowing the Company rate recovery of its estimated power supply costs for 2001. Furthermore, the Settlement Order allowed the Company to defer approximately $8.5 million in rate levelization revenues for recognition in 2002 and 2003, if necessary, to achieve its allowed rate of return. The deferred recognition of rate levelization revenues, together with the extension of our power supply agreement with MS, provides us an opportunity to recover our power supply costs in 2002 without further rate relief (See "Power Supply Commitments", "Retail Rate Cases" and "Risk Factors" in this section).

Power supply expenses constituted 75.3, 77.7, and 75.4 percent of total operating expenses for the years 2001, 2000, and 1999, respectively. Power supply expenses decreased by $10.5 million or 5.0 percent in 2001 and increased $28.3 million or 15.4 percent in 2000. The decrease in power supply expenses in 2001 compared with 2000 resulted from the following:

- a $7.7 million decrease in energy costs arising from a power supply arrangement with Hydro-Québec, discussed under the caption "Power Contract Commitments", whereby Hydro-Québec has an option to purchase energy at prices that were below market replacement costs;
- a $5.9 million decrease in Vermont Yankee costs due primarily to the timing of scheduled outages at the plant, where the outage costs including the costs of replacement power are deferred and amortized over the subsequent refueling cycle;
- a $4.5 million decrease from power purchased for resale, primarily under a power supply agreement discussed under the caption "Power Contract Commitments" below, whereby we buy power from MS that is sufficient to serve pre-established load requirements at a pre-defined price; and
- a $3.0 million decrease in Company-owned generation costs reflecting a reduction in generation used to maintain system reliability as compared to the prior year when the unavailability of certain transmission equipment required these units to run more frequently.

These amounts were partially offset by the disallowance in rates of 2000 Hydro-Québec power contract costs that required $7.5 million of those costs to be charged in 1999 and amortized as a reduction of power supply expense during 2000, $2.1 million in higher energy prices in 2001 under our MS agreement, and higher capacity costs in 2001 of approximately $1.0 million.

Power supply expenses increased by $28.3 million or 15.4 percent from 1999 to 2000. The increase in power supply expenses from 1999 to 2000 resulted from the following:

- a $20.0 million increase from power purchased for resale, primarily under a power supply agreement discussed below, whereby we buy power from MS that is sufficient to serve pre-established load requirements at a pre-defined price;
- a $7.7 million increase in energy costs arising from a power supply arrangement with Hydro-Québec, discussed below, whereby Hydro-Québec has an option to purchase energy at prices that were below market replacement costs;

- the costs to serve increased retail sales of electricity of 2.8 percent in 2001 and higher unit power supply costs; and
- a $3.6 million increase in capacity costs associated with our long-term Hydro-Québec power supply contract.

These amounts were partially offset by a reduction in 2000 of $9.7 million in losses accrued for the Hydro-Québec power cost disallowance under past regulatory rulings. Results for 1999 reflected pretax charges of $2.2 million in disallowed Hydro-Québec power costs, compared with the amortization during 2000 of accrued power expense of $7.5 million for 2000 that had been recorded in 1999. The power supply costs of Company-owned generation increased 39.3 percent or $2.2 million in 2000 due to purchases by MS under a power supply agreement discussed below and because units were dispatched for system reliability requirements due to the unavailability of certain transmission facilities.

The Independent System Operator of New England ("ISO") was created to manage the operations of the New England Power Pool ("NEPOOL") effective May 1, 1999. The ISO works as a clearinghouse for purchasers and sellers of electricity in the deregulated wholesale energy markets. Sellers place bids for the sale of their generation or purchased power resources and if demand is high enough the output from those resources is sold.

We must purchase electricity to meet customer demand during periods of high usage and to replace energy repurchased by Hydro-Québec under an arrangement negotiated in 1997. Our costs to serve demand during periods of warmer than normal temperatures in summer months and to replace such energy repurchases by Hydro-Québec rose substantially after the wholesale power markets became deregulated in 1999, which caused much greater volatility in spot prices for electricity. The cost of securing future power supplies had also risen substantially in tandem with higher summer power supply costs. The Company cannot predict the extent to which future prices will trade above historical levels of cost. If the new markets continue to experience the volatility evident during 1999 and 2000, our earnings and cash flow could be adversely impacted by a material amount.

Power Contract Commitments—On February 11, 1999, we entered into a contract with MS as a result of our power requirements solicitation in 1998. A master power purchase and sales agreement ("PPSA") defines the general contract terms under which the parties may transact. The sales under the PPSA commenced on February 12, 1999 and will terminate after all obligations under each transaction entered into by MS and the Company have been fulfilled. The PPSA was filed with the Federal Energy Regulatory Commission ("FERC") and the VPSB was notified as well. In January 2001, the PPSA was modified and extended to December 31, 2003.

The PPSA provides us with a means of managing price risks associated with changing fossil fuel prices. On a daily basis, and at MS's discretion, we sell power to MS from either (i) all or part of our portfolio of power resources at predefined operating and pricing parameters or (ii) any power resources available to us, provided that sales of power from sources other than Company-owned generation comply with the predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements. MS is also responsible for scheduling supply resources. We remain responsible for resource performance and availability. MS provides no coverage against major unscheduled outages. The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. We anticipate that arrangements we make to manage power supply risks will be on average more costly than the expected cost of fuel during the periods being hedged because these arrangements would typically incorporate a risk premium.

During 1994, we negotiated an arrangement with Hydro-Québec that reduced the cost under our 1987 contract with Hydro-Québec over the November 1995 through October 1999 period (the "July 1994 Agreement").

As part of the July 1994 Agreement, we were obligated to purchase $4.0 million (in 1994 dollars) worth of research and development work from Hydro-Québec over a four-year period (which has since been extended to 2001), and made a $6.5 million (in 1994 dollars) payment to Hydro-Québec in 1995. Hydro-Québec retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Québec.

Hydro-Québec also has the right to reduce the load factor from 75 percent to 65 percent a total three times over the life of the 1987 contract. The Company can delay such reduction by one year under the same contract. During 2001, Hydro-Québec exercised the first of these options for 2002 and the Company delayed the effective date of this exercise until 2003. The Company estimates that the net cost of Hydro-Québec's exercise of its option will increase power supply expense during 2003 by approximately $0.4 million. During the first year of the July 1994 Agreement (the period from November 1995 through October 1996), the average cost per kilowatt-hour of Schedules B and C3 combined was cut from 6.4 to 4.2 cents per kilowatt-hour, a 34 percent (or $16 million) cost reduction. Over the period from November 1996 through December 2000 and accounting for the payments to Hydro-Québec, the combined unit costs were lowered from 6.5 to 5.9 cents per kilowatt-hour, reducing unit costs by 10 percent and saving $20.7 million in nominal terms.

Under a power supply arrangement executed in January 1996 ("9601"), we received payments from Hydro-Québec of $3.0 million in 1996 and $1.1 million in 1997. Under 9601 we were required to shift up to 40 megawatts of deliveries to an alternate transmission path, and use the associated portion of the NEPOOL/Hydro-Québec interconnection facilities to purchase power for the period from September 1996 through June 2001 at prices that varied based upon conditions in effect when the purchases were made. 9601 also provided for minimum payments by the Company to Hydro-Québec for periods in which power was not purchased under the arrangement. 9601 allowed Hydro-Québec to curtail deliveries of energy should it need to use certain resources to supplement available supply. Hydro-Québec did curtail deliveries in the fourth quarter of 2000. We estimate that 9601 has provided a benefit of approximately $3.0 million on a net present value basis over the past six years.

Under a separate arrangement executed on December 5, 1997 ("9701"), Hydro-Québec paid $8.0 million to the Company in 1997. In return for this payment, we provided Hydro-Québec options for the purchase of power. Commencing April 1, 1998 and effective through the term of the 1987 Contract, which ends in 2015, Hydro-Québec 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-Québec may exercise an option to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy price. Under option B, Hydro-Québec may purchase no more than 200,000 MWh in any year. As of December 31, 2001, Hydro-Québec had purchased or called to purchase 432,000 MWh under option B.

In 2001, Hydro-Québec exercised option A and option B, and called for deliveries to third parties at a net expense to the Company of approximately $7.6 million, including capacity charges.

In 2000, Hydro-Québec exercised option A and option B, and called for deliveries to third parties at a net cost to the Company of approximately $14.0 million (including the cost of January and February, 2001 calls, and the cost of related financial positions), which was due to higher energy replacement costs incurred by the Company. Approximately $6.6 million of the $14.0 million net 9701 costs were recovered in rates on an annual basis.

In 1999, Hydro-Québec called for deliveries to third parties at a net cost to the Company of approximately $6.3 million. Hydro-Québec's option to curtail energy deliveries pursuant to the July 1994 Agreement can be exercised in addition to these purchase options.

The VPSB, in the Settlement Order stated, "The record does not demonstrate that any other New England utility foresaw the extent and degree of volatility that has developed in the New England wholesale power markets. Absent that volatility, the 97-01 Agreement would not have had adverse effects." In conjunction with the Settlement Order, Hydro-Québec committed to the Department that it would not call any energy under option B of 9701 during the contract year ending October 31, 2002.

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-Québec for its failure to deliver electricity pursuant to the VJO/Hydro-Québec 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-Québec and partially with the VJO. In the decision, the Tribunal concluded (i) the VJO/Hydro-Québec power supply contract remains in effect and Hydro-Québec 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-Québec is required to return certain capacity payments to the VJO.

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

Vermont Yankee Nuclear Power Corporation("VY")

On August 15, 2001, VY agreed to sell its nuclear power plant to Entergy Corporation for approximately $180 million. The FERC approved the Entergy purchase on January 30, 2002. The sale is subject to approval of the VPSB, the U.S. Nuclear Regulatory Commission, and other regulatory bodies. A related agreement calls for Entergy to provide the current output level of the plant to VY's present sponsors, including GMP, at average annual prices ranging from $39 to $45 per megawatt hour through 2012, subject to a "low market adjuster" effective November, 2005, that protects the Company and other sponsors in the event that market prices for power drop significantly. No additional decommission liability funding or any other financing by VY is anticipated to complete the transaction. The sale, if completed, will lower projected costs over the remaining license period for VY. The Company would continue to own its equity interest in VY, whose role would consist primarily of administering power supply contracts between Entergy and VY's present sponsors.

The VY plant currently has several fuel rods that will require repair during 2002, a maintenance requirement that is not unique to VY. There are various means of addressing the maintenance, including an estimated ten-day shutdown of the plant, or a delay in shutdown accompanied by a reduction in the generation output at the plant. At the present time, the Company is unable to estimate when the maintenance will occur or its ultimate cost, but it could be material.

Other Operating Expenses**—**Other operating expenses decreased $1.7 million, or 9.7 percent in 2001 compared with 2000. The decrease was primarily due to a $3.2 million charge during 2000 for disallowed regulatory litigation costs, ordered by the VPSB as part of the Settlement Order, offset in part by increased outside service expense during 2001.

Other operating expenses increased $0.1 million in 2000 compared with 1999. The increase was primarily due to a $3.2 million charge for disallowed regulatory litigation costs, ordered by the VPSB as part of the Settlement Order. The increase was offset by a $3.3 million decrease in administrative and general expense caused by the Company's reorganization efforts that reduced the size of the workforce and lowered building occupancy costs.

Transmission Expenses**—**Transmission expenses decreased $0.1 million or 0.8 percent in 2001 compared with 2000.

Transmission expenses increased $3.4 million or 31.8 percent in 2000 compared with 1999 primarily due to congestion charges that reflect the lack of adequate transmission or generation capacity in certain locations within New England. These charges are allocated to all ISO New England members. The Company is unable to predict the magnitude or duration of future congestion charge allocation, but amounts could be material.

In 2000, FERC issued a separate order ("Order 2000") requiring all utilities to file plans for the formation and administration of regional transmission organizations ("RTO"). In January 2001, the Company and other Vermont transmission owning companies filed in compliance with Order 2000. The Vermont companies support the Petition for Declaratory Order by various New England transmission owning companies, with reservations. The Vermont companies' principal concerns relate to:

- whether a New England RTO ("NERTO") will include all non-Pool Transmission Facilities in the NERTO Tariff on a rolled in basis;
- whether Highgate and Phase I/Phase II transmission facilities will be included in the Tariff without a separate transmission levy;
- whether NERTO will continue the transition to a single regional transmission rate; and
- the percentage of equity that transmission owners may acquire in the new organization.

It has become likely that New England will adopt separate local energy prices that reflect transmission constraints between local regions within the New England RTO. The changes are expected to become effective during 2003. The locational energy prices are likely to vary between local regions based on variables that include the amount of local generation, the cost of local transmission facilities and the congestion within the local transmission system. The Company is unable to estimate how these transmission issues will be resolved, but the negative impact on transmission expense could be material.

Maintenance Expenses**—**Maintenance expenses increased $0.5 million or 7.2 percent in 2001 compared with 2000 due to increased expenditures on right-of-way maintenance programs. Maintenance expenses decreased in 2000 by $0.1 million or 1.4 percent compared with 1999 due to reductions in scheduled maintenance.

Depreciation and Amortization**—**Depreciation and amortization expense decreased $1.0 million or 6.6 percent in 2001 compared with 2000 due to reductions in amortization of demand side management costs that were only partially offset by increased depreciation of utility plant in service. Depreciation and amortization expenses decreased $0.9 million or 5.5 percent in 2000 compared with 1999 for the same reason.

Income Taxes**—**Income tax amounts increased in 2001 due to an increase in the Company's taxable income. Income taxes decreased for 2000 due to an increase in the Company's taxable loss.

Other Income**—**Other income decreased $0.3 million in 2001 compared with 2000 due in part to reduced interest income from the reduced investment returns available in 2001. Other income decreased

$0.7 million in 2000 due to a $0.6 million gain on the 1999 sale of Green Mountain Energy Resources, Inc.

Interest Charges—Interest expense decreased $0.2 million or 3.0 percent in 2001 compared with 2000 primarily due to scheduled reductions in long-term debt offset in part by a $12 million term loan made on August 24, 2001.

Interest expense increased $0.1 million or 1.0 percent in 2000 due to increases in short-term debt and rising interest rates that were partially offset by reductions in long-term debt.

Dividends on Preferred Stock—Dividends on preferred stock decreased $81,000, or 8.0 percent in 2001 compared with 2000 due to repurchases of preferred stock. In 2000, the dividends on preferred stock decreased $141,000 or 12.2 percent for the same reason.

Environmental Matters

The electric industry typically uses or generates a range of potentially hazardous products in its operations. We must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with these requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations, 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 have previously been notified by the Environmental Protection Agency ("EPA") that we are one of several potentially responsible parties ("PRPs") for cleanup of the Pine Street Barge Canal 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 EPA, 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 EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site.

As of December 31, 2001, our total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $25.2 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 for 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 reimburse 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 Barge Canal 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 amortization of expenditures associated with the Pine Street Barge Canal 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 Barge Canal 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". The Settlement Order released January 23, 2001 did not change the status of Pine Street cost recovery.

Clean Air Act—Because we purchase most of our power supply from other utilities, we do not anticipate that we will incur any material direct cost increases as a result of the Federal Clean Air Act or proposals to make more stringent regulations under that Act. Furthermore, only one of our power supply purchase contracts, which expired in early 1998, related to a generating plant that was affected by Phase I of the acid rain provisions of this legislation, which went into effect January 1, 1995.

Rates

Retail Rate Cases—The Company reached a final settlement agreement with the Department in its 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-Québec 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 replaces 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 can be utilized 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 earned approximately $30,000 in excess of its allowed rate of return during 2001 before writing off regulatory assets in the same amount.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions:
- The Company and customers shall share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share; and
- The Company's further investment in non-utility operations is restricted.

Liquidity and Capital Resources

***Construction*—**Our capital requirements result from the need to construct facilities or to invest in programs to meet anticipated customer demand for electric service. Capital expenditures, net of customer advances for construction, over the past three years and forecasted for 2002 are as shown at the bottom of this page.

***Dividend Policy*—**The annual dividend rate was $0.55 per share at December 31, 2001.

The Settlement Order limits the dividend rate at its current level until short-term credit facilities are replaced with long-term debt or equity financing. Retained earnings at December 31, 2001 were approximately $8.1 million. The Company recorded substantial improvement in retained earnings during 2001 and, with continued growth in retained earnings, believes it will be able to gradually increase the current dividend rate after restructuring its credit arrangements. If retained earnings were eliminated, the Company would not be able to declare a dividend under its Restated Articles of Association.

***Financing and Capitalization*—**Internally-generated funds provided approximately 100 percent, 41 percent, and 92 percent of requirements for 2001, 2000 and 1999, respectively. Internally generated funds, after payment of dividends, provide capital requirements for construction, sinking funds and other requirements. We anticipate that for 2002, internally generated funds will provide approximately 90 percent of total capital requirements for regulated operations.

The Company is not dependent on the use of off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets through special purpose entities. We do have material power supply commitments that are discussed in detail under the captions Power Contract Commitments and Power Supply Expenses.

At December 31, 2001, our capitalization consisted of 51.2 percent common equity, 42.5 percent long-term debt and 6.3 percent preferred equity.

The Company has a $15.0 million, 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by KeyBank National Association, ("KeyBank") expiring June 2002 (the "Fleet-Key Agreement"). The Fleet-Key Agreement replaced a similar agreement with Fleet and Citizens Bank of Massachusetts (the "Fleet agreement") in the amount of $15.0 million, with borrowings outstanding of $500,000, with weighted average rate of 9.5 percent, at December 31, 2000. There were no amounts outstanding on the Fleet-Key Agreement at December 31, 2001. There was no non-utility short-term debt outstanding at December 31, 2001. The Fleet-Key Agreement is unsecured.

On September 20, 2000, we established a $15.0 million revolving credit agreement with KeyBank. The Company was required to invest $15.0 million provided to GMP by Energy East Corporation ("EE"), pursuant to a power supply option agreement, in a certificate of deposit at KeyBank pledged by the Company to secure the repayment of the Keybank revolving credit facility. The payment made by EE was returned with accrued interest on September 11, 2001. The KeyBank agreement expired on September 19, 2001.

On July 27, 2001, the VPSB approved a $12.0 million two-year unsecured loan agreement, with Fleet, joined by KeyBank, and the loan was made to GMP on August 24, 2001. The Company used this facility, along with proceeds from the maturing KeyBank certificate of deposit; to terminate the KeyBank agreement, and repay the $15.0 million it received from EE pursuant to the power supply option agreement. At December 31, 2001, there was $12.0 million outstanding under the two-year loan agreement.

The Company has initiated an early redemption of the Company's 10 percent first mortgage bonds maturing June 2004. The bonds currently have $5.1 million outstanding and annual sinking fund requirements of $1.7 million.

On March 4, 2002, the Vermont Department of Public Service announced its endorsement of the proposed sale of the Vermont Yankee nuclear plant to Entergy Nuclear Corp., as discussed in Note B.

On March 12, 2002, the Company purchased $10.0 million of the Company's 7.32 percent, Class E, Series 1 preferred stock outstanding for approximately $10.1 million.

Capital Expenditures

	Generation	Transmission	Distribution	Conservation	Other*	Total Net Expenditures
			(Dollars in thousands and net of AFUDC and customer advances for construction)			
Actual:						
1999	$ 211	$ 144	$5,930	$1,943	$9,038	$17,266
2000	1,937	348	7,316	**	5,876	15,477
2001	2,323	1,219	8,567	**	3,529	15,638
Forecasted:						
2002	$3,258	$1,827	$9,173	**	$5,447	$19,705

*Other includes $6.1 million in 1999, $1.3 million in 2000, and $1.5 million in 2001 for the Pine Street Barge Canal site.
**A statewide Energy Efficiency Utility set up by the VPSB in 1999 manages all energy efficiency programs, receiving funds the Company bills to its customers as a separate charge.

See Note B, Investments in Associated Companies, Note D, Preferred Stock, Note F, Long-Term Debt, and Note M, Subsequent Events for additional information.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2002. The credit ratings of the Company's securities at December 31, 2001 are:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BBB	Baa2	BBB
Preferred stock	BBB–	ba2	BB

During the first quarter of 2001, Moody's Investors Service and Fitch upgraded the Company's first mortgage bond and preferred stock ratings. The rating actions reflected the rating agencies' earnings and cash flow expectations for the Company following the Settlement Order.

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.

Future Outlook

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 generating capacity among and within various regions of the country;
- improvements in generation efficiency;
- increasing demand for customer choice;
- new regulations and legislation intended to foster competition, also known as restructuring; and
- increasing volatility of wholesale market prices for electricity.

Electric utilities historically have had exclusive franchises for the retail sale of electricity in specified service territories. As a result, competition for retail customers has been limited to:

- competition with alternative fuel suppliers, primarily for heating and cooling;
- competition with customer-owned generation; and
- direct competition among electric utilities to attract major new facilities to their service territories.

These competitive pressures have led the Company and other utilities to offer, from time to time, special discounts or service packages to certain large customers.

In certain states across the country, including all the New England states except Vermont, legislation has been enacted to allow retail customers to choose their electricity suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems (also known as retail wheeling). Increased pressure in the electric utility industry may restrict the Company's ability to charge energy prices sufficient to recover costs of service, such as the cost of purchased power obligations or of generation facilities owned by the Company. The amount by which such costs might exceed market prices is commonly referred to as stranded costs.

Regulatory and legislative authorities at the federal level and in some states, including Vermont where legislation has not been enacted, are considering whether, when and how to facilitate competition for electricity sales at the retail level. Recent difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards deregulation in Vermont. However, in the future, the Vermont General Assembly through legislation, or the VPSB through a subsequent report, action or proceeding, may allow customers to choose their electric supplier. If this happens without providing for recovery of a significant portion of the costs associated with our power supply obligations and other costs of providing vertically integrated service, the Company's franchise, including our operating results, cash flows and ability to pay dividends at the current level, would be adversely affected.

Nuclear Decommissioning—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 issued a new statement in August 2001 for "Accounting for Asset Retirement Obligations", which provides guidance on accounting for nuclear plant decommissioning costs. The Company has not yet determined what impact, if any, the new accounting standard will have on its investment in VY. We do not believe that changes in such accounting, if required, would have an adverse effect on the results of our operations due to our current and future ability to recover decommissioning costs through rates.

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

Consolidated Statements of Income

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2001	2000	1999
	(In thousands, except amounts per share)		
Operating Revenues	**$283,464**	$277,326	$251,048
Operating Expenses			
Power Supply			
Vermont Yankee Nuclear Power Corporation	**30,114**	34,813	34,987
Company-owned generation	**4,742**	7,777	5,582
Purchases from others	**166,209**	168,947	142,699
Other operating	**15,924**	17,644	17,582
Transmission	**14,130**	14,237	10,800
Maintenance	**7,108**	6,633	6,728
Depreciation and amortization	**14,294**	15,304	16,187
Taxes other than income	**7,536**	7,402	7,295
Income taxes	**6,948**	(691)	1,242
Total operating expenses	**267,005**	272,066	243,102
Operating income	**16,459**	5,260	7,946
Other Income			
Equity in earnings of affiliates and non-utility operations	**2,253**	2,495	2,919
Allowance for equity funds used during construction	**210**	284	134
Other (deductions) income, net	**(90)**	(73)	400
Total other income	**2,373**	2,706	3,453
Income before interest charges	**18,832**	7,966	11,399
Interest Charges			
Long-term debt	**6,073**	6,499	6,716
Other	**1,154**	986	558
Allowance for borrowed funds used during construction	**(188)**	(228)	(91)
Total interest charges	**7,039**	7,257	7,183
Income before preferred dividends and discontinued operations	**11,793**	709	4,216
Dividends on preferred stock	**933**	1,014	1,155
Income (loss) from continuing operations	**10,860**	(305)	3,061
Net loss from discontinued segment operations, net of applicable income taxes	**—**	—	(603)
Loss on disposal, including provisions for operating losses during phaseout period, net of applicable income taxes	**(182)**	(6,549)	(6,676)
Net Income (Loss) Applicable to Common Stock	**$ 10,678**	($ 6,854)	($ 4,218)
Earnings per Share			
Basic earnings (loss) per share from continuing operations	**$ 1.93**	($ 0.06)	$ 0.57
Basic earnings (loss) per share from discontinued operations	**(0.03)**	(1.19)	(1.36)
Basic earnings (loss) per share	**$ 1.90**	($ 1.25)	$ 0.79
Diluted earnings (loss) per share from continuing operations	**$ 1.88**	($ 0.06)	$ 0.57
Diluted earnings (loss) per share from discontinued operations	**(0.03)**	(1.19)	(1.36)
Diluted earnings (loss) per share	**$ 1.85**	($ 1.25)	$ 0.79
Cash dividends declared per share	**$ 0.55**	$ 0.55	$ 0.55
Weighted average shares outstanding–basic	**5,630**	5,491	5,361
Weighted average equivalent shares outstanding–diluted	**5,789**	5,491	5,361

Consolidated Statements of Retained Earnings

	2001	2000	1999
Balance—beginning of period	**$ 493**	$ 10,344	$ 17,508
Net Income (loss)	**11,611**	(5,840)	(3,063)
	12,104	4,504	14,445
Cash Dividends—redeemable cumulative preferred stock	**933**	1,014	1,155
Cash Dividends—common stock	**3,101**	2,997	2,946
	4,034	4,011	4,101
Balance—end of period	**$ 8,070**	$ 493	$ 10,344

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

Consolidated Statements of Cash Flows

GREEN MOUNTAIN POWER CORPORATION • For the Twelve Months Ended December 31

	2001	2000	1999
		(In thousands)	
Operating Activities:			
Net Income (Loss) before preferred dividends	$ 11,611	($ 5,840)	($3,063)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	14,294	15,304	16,187
Dividends from associated companies less equity income	280	(26)	169
Allowance for funds used during construction	(398)	(512)	(224)
Amortization of purchased power costs	3,767	5,575	5,725
Deferred income taxes	(2,167)	161	1,530
Provision for chargeoff of deferred regulatory asset	—	3,229	—
Deferred purchased power costs	1,126	(6,692)	(6,590)
Accrued purchased power contract option call	(8,276)	8,276	—
Provision for loss on segment disposal	182	6,549	6,676
Arbitration costs recovered (deferred)	3,229	(3,184)	(1,684)
Rate levelization liability	8,527	—	—
Environmental and conservation deferrals, net	(3,380)	(2,073)	(8,048)
Changes in:			
Accounts receivable	5,254	(3,862)	474
Accrued utility revenues	1,229	(125)	(358)
Fuel, materials and supplies	(2)	(766)	(150)
Prepayments and other current assets	302	(165)	4,009
Accounts payable	(666)	3,004	665
Accrued income taxes payable and receivable	1,187	(372)	(1,611)
Other current liabilities	794	(7,341)	1,722
Other	(1,603)	(181)	(324)
Net cash provided by continuing operations	35,290	10,959	15,105
Net change in discontinued segment	(1,797)	245	(138)
Net cash provided by operating activities	33,493	11,204	14,967
Investing Activities:			
Construction expenditures	(12,963)	(13,853)	(9,174)
Proceeds from subsidiary sales	—	6,000	—
Investment in non-utility property	(212)	(187)	(190)
Net cash used in investing activities	(13,175)	(8,040)	(9,364)
Financing Activities:			
Proceeds from term loan	12,000	—	—
Reduction in preferred stock	(235)	(1640)	(1,650)
Issuance of common stock	1,655	1,250	1,054
Proceeds (Purchases) of Certificate of Deposit	16,173	(15,437)	—
Power supply option obligations	(16,012)	15,419	—
Reduction in long-term debt	(9,700)	(6,700)	(1,700)
Short-term debt, net	(15,500)	7,600	900
Cash dividends	(4,034)	(4,011)	(4,101)
Net cash used in financing activities	(15,653)	(3,519)	(5,497)
Net increase (decrease) in cash and cash equivalents	4,665	(355)	106
Cash and cash equivalents at beginning of period	341	696	590
Cash and Cash Equivalents at End of Period	$ 5,006	$ 341	$ 696
Supplemental Disclosure of Cash Flow Information:			
Cash paid year-to-date for:			
Interest (net of amounts capitalized)	$ 6,936	$ 7,185	$ 7,034
Income taxes, net	9,622	1,191	997

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

Consolidated Capitalization Data

GREEN MOUNTAIN POWER CORPORATION • December 31

COMMON STOCK	Shares Authorized	Shares Issued and Outstanding 2001	Shares Issued and Outstanding 2000	2001 (In thousands)	2000 (In thousands)
Common Stock,					
$3.33⅓ par value	10,000,000	**5,685,154**	5,566,696	**$19,004**	$18,608

	Authorized	Issued	Outstanding 2001	Outstanding 2000	2001 (In thousands)	2000 (In thousands)
Redeemable Cumulative Preferred Stock,						
$100 par value						
4.75%, Class B,						
redeemable at $101 per share	15,000	15,000	**1,150**	1,450	**$ 115**	$ 145
7%, Class C,						
redeemable at $101 per share	15,000	15,000	**2,850**	3,300	**285**	330
9.375%, Class D, Series 1,						
redeemable at $101 per share	40,000	40,000	**1,600**	3,200	**160**	320
7.32%, Class E, Series 1	200,000	120,000	**120,000**	120,000	**12,000**	12,000
Total Preferred Stock					**$12,560**	$12,795

LONG-TERM DEBT	2001 (In thousands)	2000 (In thousands)
Fleet–Key Term Loan Due August 2003	**$12,000**	$ —
First Mortgage Bonds		
6.21% Series due 2001	**—**	8,000
6.29% Series due 2002	**8,000**	8,000
6.41% Series due 2003	**8,000**	8,000
10.0% Series due 2004—Cash sinking fund, $1,700,000 annually	**5,100**	6,800
7.05% Series due 2006	**4,000**	4,000
7.18% Series due 2006	**10,000**	10,000
6.7% Series due 2018	**15,000**	15,000
9.64% Series due 2020	**9,000**	9,000
8.65% Series due 2022—Cash sinking fund, commences 2012	**13,000**	13,000
Total Long-term Debt Outstanding	**84,100**	81,800
Less Current Maturities (due within one year)	**9,700**	9,700
Total Long-term Debt, Less Current Maturities	**$74,400**	$72,100

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

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • December 31

ASSETS	2001	2000
	(In thousands)	
Utility Plant		
Utility plant, at original cost	**$302,489**	$291,107
Less accumulated depreciation	**119,054**	110,273
Net utility plant	**183,435**	180,834
Property under capital lease	**5,959**	6,449
Construction work in progress	**7,464**	7,389
Total utility plant, net	**196,858**	194,672
Other Investments		
Associated companies, at equity	**14,093**	14,373
Other investments	**6,852**	6,357
Total other investments	**20,945**	20,730
Current Assets		
Cash and cash equivalents	**5,006**	341
Certificate of deposit, pledged as collateral	**—**	15,437
Accounts receivable, less allowance for doubtful accounts of $613 and $463	**17,111**	22,365
Accrued utility revenues	**5,864**	7,093
Fuel, materials and supplies, at average cost	**4,058**	4,056
Prepayments	**1,976**	2,525
Income tax receivable	**1,699**	1,613
Other	**469**	222
Total current assets	**36,183**	53,652
Deferred Charges		
Demand side management programs	**6,961**	6,358
Purchased power costs	**3,504**	11,789
Pine Street Barge Canal	**12,425**	12,370
Power supply derivative deferral	**37,313**	—
Other	**14,870**	15,519
Total deferred charges	**75,073**	46,036
Non-Utility		
Other current assets	**8**	8
Property and equipment	**250**	252
Other assets	**817**	1,258
Total non-utility assets	**1,075**	1,518
Total Assets	**$330,134**	$316,608

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

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • December 31

CAPITALIZATION AND LIABILITIES	2001	2000
	(In thousands, except share data)	
Capitalization		
Common Stock Equity		
Common stock, $3.33⅓ par value, authorized 10,000,000 shares (issued 5,701,010 and 5,582,552)	$ 19,004	$ 18,608
Additional paid-in capital	74,581	73,321
Retained earnings	8,070	493
Treasury stock, at cost (15,856 shares)	(378)	(378)
Total common stock equity	101,277	92,044
Redeemable cumulative preferred stock	12,325	12,560
Long-term debt, less current maturities	74,400	72,100
Total capitalization	188,002	176,704
Capital Lease Obligation	5,959	6,449
Current Liabilities		
Current maturities of preferred stock	235	235
Current maturities of long-term debt	9,700	9,700
Short-term debt	—	15,500
Accounts payable, trade, and accrued liabilities	7,237	7,755
Accounts payable to associated companies	8,361	8,510
Rate levelization liability	8,527	—
Customer deposits	971	696
Purchased power call option liability	—	8,276
Interest accrued	1,100	1,150
Energy East power supply obligation	—	15,419
Other	2,945	1,103
Total current liabilities	39,076	68,344
Deferred Credits		
Power supply derivative liability	37,313	—
Accumulated deferred income taxes	23,759	25,644
Unamortized investment tax credits	3,413	3,695
Pine Street Barge Canal cleanup liability	10,059	11,554
Other	20,852	20,901
Total deferred credits	95,396	61,794
COMMITMENTS AND CONTINGENCIES		
Non-Utility		
Liabilities of discontinued segment, net	1,701	3,317
Total non-utility liabilities	1,701	3,317
Total Capitalization and Liabilities	$330,134	$316,608

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

A Significant Accounting Policies

1. Organization and Basis of Presentation

Green Mountain Power Corporation (the "Company") is an investor-owned electric services company located in Vermont with a principal service territory that includes approximately one-quarter of Vermont's population. Nearly all of the Company's net income is generated from its regulated electric utility operation, which purchases and generates electric power and distributes it to approximately 87,000 retail and wholesale customers. At December 31, 2001, the Company's primary subsidiary investment was Northern Water Resources, Inc. ("NWR"), formerly known as Mountain Energy, Inc., which had invested in energy generation, energy efficiency and wastewater treatment projects across the United States. In 2000, the Company disposed of most of the assets of NWR, and reports its results as income (loss) from operations of a discontinued segment. In 1998, the Company sold the assets of its wholly-owned subsidiary, Green Mountain Propane Gas Company ("GMPG"). The Company's remaining wholly-owned subsidiaries, which are not regulated by the Vermont Public Service Board ("VPSB" or the "Board"), are Green Mountain Resources, Inc. ("GMRI"), which sold its remaining interest in Green Mountain Energy Resources in 1999 and is currently inactive, and GMP Real Estate Corporation. 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. Summarized financial information for these subsidiaries is as follows:

	For the years ended December 31, 2001	2000	1999
		(In thousands)	
Revenues	$1,012	$1,034	$1,286
Expenses	575	495	184
Net income	$ 437	$ 539	$1,102

The Company accounts for its investments in various associated companies, Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VY"), Vermont Electric Power Company, Inc. ("VELCO"), New England Hydro-Transmission Corporation, and New England Hydro-Transmission Electric Company using the equity method of accounting. The Company's share of the net earnings or losses of these companies is also included in the Other Income section of the Consolidated Statements of Income. See Note B and Note L for additional information.

2. Regulatory Accounting

The Company's utility operations, including accounting records, rates, operations and certain other practices of its electric utility business, are subject to the regulatory authority of the Federal Energy Regulatory Commission ("FERC") and the VPSB.

The accompanying consolidated financial statements conform to accounting principles generally accepted in the United States applicable to rate-regulated enterprises in accordance with Statement of Financial Accounting Standards No. 71 ("SFAS 71"), Accounting for Certain Types of Regulation. Under SFAS 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. Conditions that could give rise to the discontinuance of SFAS 71 include increasing competition that restricts the Company's ability to recover specific costs, and a change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. In the event that the Company no longer meets the criteria under SFAS 71, the Company would be required to write off related regulatory assets and liabilities as summarized in the following table:

SFAS 71 Deferred Charges	At December 31, 2001	2000
	(In thousands)	
Power Supply Derivative	$37,313	$ —
Pine Street Barge Canal	12,425	12,370
Power Supply	6,112	15,689
Demand Side Management	6,961	6,358
Preliminary Survey	1,094	1,040
Storm Damages	2,169	2,102
Regulatory Commission Costs	873	459
Tree Trimming	905	999
Restructuring Costs	3,502	4,788
Other	2,895	3,749
Total Deferred Charges	$74,249	$47,554

The Company continues to believe, based on current regulatory circumstances, that the use of regulatory accounting under SFAS 71 remains appropriate and that its regulatory assets are probable of recovery. Regulatory entities that influence the Company include the VPSB, the Vermont Department of Public Service ("DPS" or the "Department"), and FERC, among other federal, state and local regulatory agencies.

3. Impairment

The Company is required to evaluate long-lived assets, including regulatory assets, for potential impairment. Assets that are no longer probable of recovery through future revenues would be revalued based upon future cash flows. Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. As of December 31, 2001, based upon the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss should be recorded. Competitive influences or regulatory developments may impact this status in the future.

4. Utility Plant

The cost of plant additions includes all construction-related direct labor and materials, as well as indirect construction costs, including the cost of money ("Allowance for Funds Used During Construction" or "AFUDC"). As part of a rate agreement with the DPS, the Company discontinued recording AFUDC on construction work in progress in January 2001. The costs of renewals and improvements of property units are capitalized. The costs of maintenance, repairs and replacements of minor property items are charged to maintenance expense. The costs of units of property removed from service, net of removal costs and salvage, are charged to accumulated depreciation.

5. Depreciation

The Company provides for depreciation using the straight-line method based on the cost and estimated remaining service life of the depreciable property outstanding at the beginning of the year and adjusted for salvage value and cost of removal of the property. Accounting for costs of removal could be affected by the new accounting standard on asset retirement obligations as discussed under the caption "New Accounting Standards".

The annual depreciation provision was approximately 3.5 percent of total depreciable property at the beginning of 2001, 3.5 percent at the beginning of 2000 and 3.3 percent at the beginning of 1999.

6. Cash and Cash Equivalents

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

7. Operating Revenues

Operating revenues consist principally of sales of electric energy at regulated rates. The Company accrues utility revenues, based on estimates of electric service rendered and not billed at the end of an accounting period, in order to match revenues with related costs.

8. Deferred Charges

In a manner consistent with authorized or expected ratemaking treatment, the Company defers and amortizes certain replacement power, maintenance and other costs associated with the Vermont Yankee Nuclear Power Corporation's generation plant. In addition, the Company accrues and amortizes other replacement power expenses to reflect more accurately its cost of service to better match revenues and expenses consistent with regulatory treatment. The Company also defers and amortizes costs associated with its investment in its demand side management program.

Other deferred charges totaled $14.9 million and $15.5 million at December 31, 2001 and 2000, respectively, consisting of regulatory deferrals of storm damages, rights-of-way maintenance, other employee benefits, preliminary survey and investigation charges, transmission interconnection charges, regulatory tax assets and various other projects and deferrals.

9. Earnings Per Share

Earnings per share are based on the weighted average number of common and common stock equivalent shares outstanding during each year. During the year ended December 31, 2000, the Company established a stock incentive plan for all employees, and granted 335,300 options exercisable over vesting schedules of between one and four years. During 2001, the Company granted an additional 56,450 options. See Note C for additional information.

10. Major Customers

The Company had one major retail customer, International Business Machines ("IBM"), metered at two locations, that accounted for 26.6 percent, 26.6 percent, and 25.9 percent of retail MWh sales, and 19.2 percent, 16.5 percent and 16.2 percent of the Company's retail operating revenues in 2001, 2000 and 1999, respectively. IBM's percent of retail operating revenues in 2001 increased due to a rate increase.

11. Fair Value of Financial Instruments

The present value of the first mortgage bonds and preferred stock outstanding, if refinanced using prevailing market rates of interest, would decrease from the balances outstanding at December 31, 2001 by approximately 7.3 percent. In the event of such a refinancing, there would be no gain or loss because under established regulatory precedent, any such difference would be reflected in rates and have no effect upon net income.

12. Deferred Credits

At December 31, 2001, the Company had other deferred credits and long-term liabilities of $20.9 million, consisting of reserves for damage claims, and accruals for employee benefits compared with a balance of $20.9 million at December 31, 2000.

13. Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and assumptions that affect assets and liabilities, the disclosure of contingent assets and liabilities, and revenues and expenses. Actual results could differ from those estimates.

14. Reclassifications

Certain items on the prior year's consolidated financial statements have been reclassified to be consistent with the current year presentation.

15. New Accounting Standards

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended ("SFAS 133").

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 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. Futures, swaps and forward contracts are used to hedge market prices should option calls by Hydro-Québec be exercised. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions.

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 December 31, 2001, the Company had a liability reflecting the negative fair value of the two derivatives described below, as well as a corresponding regulatory asset of approximately $37.3 million. The Company believes that the regulatory asset 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, 2003. Management's estimate of the fair value of the future net cost of this arrangement at December 31, 2001 is approximately $11.6 million.

We also sometimes use future contracts to hedge forecasted wholesale sales of electric power, including material sales commitments as discussed in Note K. We currently have an arrangement with Hydro-Québec that grants them 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 December 31, 2001 is approximately $25.7 million.

In June 2001, the 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 initiated after June 30, 2001 and uses a non-amortization approach to purchased goodwill and other indefinite-lived intangible assets. Under SFAS 142, effective for fiscal years beginning after December 15, 2001, goodwill and intangible assets deemed to have indefinite lives, will no longer be amortized, and will be subject to annual impairment tests. The

Company does not expect the application of these accounting standards to materially impact its financial position or results of operations.

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 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 not yet determined what impact, if any, the accounting standard will have on its financial position or results of operations.

In October 2001, the FASB issued Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"). SFAS 144 specifies accounting and reporting for the impairment or disposal of long-lived assets. The Company has not yet quantified the impact, if any, of adopting SFAS 144 on its financial position or results of operations.

B Investments in Associated Companies

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

	Percent Ownership at December 31, 2001	Investment in Equity December 31, 2001	2000
		(In thousands)	
VELCO–Common	29.50%	$ 1,932	$ 1,916
–Preferred	30.00%	420	540
Total VELCO		2,352	2,456
Vermont Yankee–Common	17.88%	9,725	9,713
New England Hydro-Transmission–Common	3.18%	761	827
New England Hydro-Transmission Electric–Common	3.18%	1,255	1,377
Total investment in associated companies		$14,093	$14,373

Undistributed earnings in associated companies totaled approximately $522,000 at December 31, 2001.

VELCO

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 other electric utilities, and under these agreements, VELCO bills all costs, including interest on debt and a fixed return on equity, to the State and others using VELCO's transmission system. The Company's purchases of transmission services from VELCO were $11.5 million, $9.8 million, and $7.9 million for the years 2001, 2000 and 1999, respectively. Pursuant to VELCO's Amended Articles of Association, the Company is entitled to approximately 30 percent of the dividends distributed by VELCO. The Company has recorded its equity in earnings on this basis and also is obligated to provide its proportionate share of the equity capital requirements of VELCO through continuing purchases of its common stock, if necessary.

Summarized financial information for VELCO is as follows:

	At and for the years ended December 31, 2001	2000	1999
		(In thousands)	
Company's equity in net income	$ 308	$ 395	$ 357
Total assets	$89,370	$82,123	$67,294
Less:			
Liabilities and long-term debt	81,448	73,874	58,731
Net assets	$ 7,922	$ 8,249	$ 8,563
Company's equity in net assets	$ 2,352	$ 2,456	$ 2,529

Vermont Yankee

At December 31, 2001, the Company was responsible for approximately 17.9 percent of Vermont Yankee's expenses of operations, including costs of equity capital and estimated costs of decommissioning, and is entitled to a similar share of the power output of the nuclear plant, which has a net capacity of 531 megawatts. Vermont Yankee's estimate of the current cost of decommissioning is approximately $471 million, using the 1993 FERC approved escalation rate of 5.4% through 2000, and 4.25% thereafter, of which $297 million has been funded. At December 31, 2001, the Company's portion of the net unfunded liability was $31 million, which it expects will be recovered through rates over Vermont Yankee's remaining operating life, if the plant is not sold. As a sponsor of Vermont Yankee, the Company also is obligated to provide to VY 20 percent of capital requirements not obtained by outside sources. During 2001, the Company incurred $28.8 million in Vermont Yankee annual capacity charges, which included $1.9 million for interest charges. The Company's share of Vermont Yankee's long-term debt at December 31, 2001 was $10.6 million.

On August 15, 2001, VY agreed to sell its nuclear power plant to Entergy Corporation for approximately $180 million. On January 30, 2002, the Federal Energy Regulatory Commission approved the Entergy purchase. The sale is subject to approval of the VPSB, the U.S. Nuclear Regulatory Commission and other regulatory bodies. A related agreement calls for Entergy to provide the current output level of the plant to VY's present sponsors, including the Company, at average annual prices ranging from $39 to $45 per megawatthour through 2012, subject to a "low market adjuster" effective November, 2005, that protects the Company and other sponsors in the event that market prices for power drop significantly. No additional decommission liability funding or any other financing by VY is anticipated to complete the transaction. The sale, if completed, will lower projected costs over the remaining license period for VY. The Company would continue to own its equity interest in VY. See Note M, Subsequent Events.

During January 2002, several VY stockholders who had asserted their dissenters' rights sold their shares back to VY. As a result of the stock buyback, the Company expects to record a charge of $0.4 million in January 2002.

The Price-Anderson Act currently limits public liability from a single incident at a nuclear power plant to $9.5 billion. Any damages beyond $9.5 billion are indemnified under the Price-Anderson Act, but subject to congressional approval. The first $200 million of liability coverage is the maximum provided by private insurance. The Secondary Financial Protection Program is a retrospective insurance plan providing additional coverage up to $9.3 billion per incident by assessing each of the 106 reactor units that are currently subject to the Program in the United States a total of $88.1 million, limited to a maximum assessment of $10 million per incident per nuclear unit in any one year. The maximum assessment is adjusted at least every five years to reflect inflationary changes.

The Price-Anderson Act has been renewed three times since it was first enacted in 1957. The Act will expire in August 2002 and Congress is considering reauthorization of this legislation.

The above insurance covers all workers employed at nuclear facilities for bodily injury claims. Vermont Yankee retains a potential obligation for retrospective adjustments due to past operations of several smaller facilities that did not join the above insurance program. These exposures will cease to exist no later than December 31, 2007. Vermont Yankee's maximum retrospective obligation is $3.1 million. Insurance has been purchased from Nuclear Electric Insurance Limited ("NEIL") to cover the costs of property damage, decontamination or premature decommissioning resulting from a nuclear incident. All companies insured with NEIL are subject to retroactive assessments if losses exceed the accumulated funds available. The maximum potential assessment against Vermont Yankee with respect to NEIL losses arising during the current policy year is $16.2 million. Vermont Yankee's liability for the retrospective premium adjustment for any policy year ceases six years after the end of that policy year unless prior demand has been made.

Summarized financial information for Vermont Yankee is as follows:

	At and for the years ended December 31, 2001	2000	1999
	(In thousands)		
Earnings:			
Operating revenues	$178,840	$178,294	$208,812
Net income applicable to common stock	$ 6,119	$ 6,583	$ 6,471
Company's equity in net income	$ 1,131	$ 1,177	$ 1,165
Total assets	$723,815	$706,984	$685,292
Less:			
Liabilities and long-term debt	669,640	652,663	631,365
Net assets	$ 54,175	$ 54,321	$ 53,927
Company's equity in net assets	$ 9,725	$ 9,713	$ 9,641

C Common Stock Equity

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 423,985 shares were reserved and unissued at December 31, 2001. The Company also funds an Employee Savings and Investment Plan ("ESIP"). At December 31, 2001, there were 105,067 shares reserved and unissued under the ESIP.

During 2000, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established a stock incentive plan. Under this plan, options for a total of 500,000 shares may be granted to any employee, officer, consultant, contractor or Director providing services to the Company. Outstanding options become exercisable at between one and four years after the grant date and remain exercisable until 10 years from the grant date.

As permitted by Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation,"("SFAS 123") the Company has elected to follow Accounting Principles Board Opinion No. 25 ("APB 25") "Accounting for Stock Issued to Employees", and related interpretations in accounting for its employee stock options. Under APB 25, because the exercise price equals the market price of the underlying stock on the date of grant, no compensation expense is recorded. Options have only been issued to employees and directors.

Disclosure of pro-forma information regarding net income and earnings per share is required by SFAS 123. The information presented below has been determined as if the Company accounted for its employee stock options under the fair value method of that statement. The fair values of the options granted in 2001 and 2000 are $4.16 and $2.03 per share, respectively. They were estimated at the grant date using the Black-Scholes option-pricing model. The table shown at the bottom of this page presents information about the assumptions that were used for each plan year, and a summary of the options outstanding at December 31, 2001.

Pro-forma net earnings (loss) per share and a summary of options outstanding are as follows:

Pro-forma net income (loss)	2001	2000
	(In thousands, except per share amounts)	
Net income (loss) reported	$10,678	($6,854)
Pro-forma net income (loss)	$10,515	($6,913)
Net income (loss) per share		
As reported	$1.90	($1.25)
Pro-forma	$1.87	($1.26)
Diluted earnings per share		
As reported	$1.85	($1.25)
Pro-forma	$1.82	($1.26)

	Total Options	Weighted Average Price	Range of Exercise Prices	Options Exercisable
Outstanding at 1/1/00	—	$ —	$ —	—
Granted	335,300	7.90	7.90	
Exercised	—	—	—	
Forfeited	3,400	7.90	—	
Outstanding at 12/31/00	331,900	$ 7.90	$ 7.90	
Granted	55,450	$16.67	$14.50–16.78	
Granted	1,000	12.28	12.28	
Exercised	17,400	7.90	7.90	
Forfeited	6,800	10.61	7.90–16.78	
Outstanding at 12/31/01	364,150	$ 9.20	$ 7.90–16.78	95,350

Options granted are not exercisable until one year after the date of grant. The pro-forma amounts may not be representative of future results and additional options may be granted in future years. For 2000, the number of total shares after giving effect to anti-dilutive common stock equivalents does not change.

The following table presents a reconciliation of net income to net income available to common shareholders, and the average common shares to average common equivalent shares outstanding:

Reconciliation of net income available for common shareholders and average shares	For the years ended December 31, 2001	2000	1999
	(In thousands)		
Net income (loss) before preferred dividends	$11,611	($5,840)	($3,063)
Preferred stock dividend requirement	933	1,014	1,155
Net income (loss) applicable to common stock	$10,678	($6,854)	($4,218)
Average number of common shares–basic	5,630	5,491	5,361
Dilutive effect of stock options	159	—	—
Average number of common shares–diluted	5,789	5,491	5,361

Plan Year	Weighted Average Exercise Price	Outstanding Options	Remaining Contractual Life	Assumptions used in option pricing model: Risk Free Interest Rate	Expected Life in Years	Expected Stock Volatility	Dividend Yield
2000	$ 7.90	309,900	8.6 years	6.05%	7	30.58	4.5%
2001	16.61	54,250	9.5 years	5.25%	6	32.69	4.0%
	$ 9.20	364,150					

(Dollars in thousands)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Stock Equity
BALANCE, December 31, 1998	**5,313,296**	**$17,711**	**$71,914**	**$17,508**	**15,856**	**($378)**	**$106,755**
Common Stock Issuance:							
DRIP	67,525	225	418				643
ESIP	48,277	161	345				506
Compensation Program:							
Restricted Shares	(3,527)	(12)	(83)				(95)
Net Loss				(3,063)			(3,063)
Cash Dividends:							
Common Stock				(2,946)			(2,946)
Preferred Stock—$4.75 per share				(10)			(10)
—$7.00 per share				(29)			(29)
—$9.375 per share				(57)			(57)
—$8.625 per share				(181)			(181)
—$7.32 per share				(878)			(878)
BALANCE, December 31, 1999	**5,425,571**	**18,085**	**72,594**	**10,344**	**15,856**	**(378)**	**100,645**
Common Stock Issuance:							
DRIP	73,859	246	363				609
ESIP	83,931	280	401				681
Compensation Program:							
Restricted Shares	(809)	(3)	(37)				(40)
Net Loss				(5,840)			(5,840)
Cash Dividends:							
Common Stock				(2,997)			(2,997)
Preferred Stock—$4.75 per share				(8)			(8)
—$7.00 per share				(26)			(26)
—$9.375 per share				(42)			(42)
—$8.625 per share				(60)			(60)
—$7.32 per share				(878)			(878)
BALANCE, December 31, 2000	**5,582,552**	**18,608**	**73,321**	**493**	**15,856**	**(378)**	**92,044**
Common Stock Issuance:							
DRIP	30,087	100	352				452
ESIP	75,680	252	866				1,118
Compensation Programs:							
Restricted Shares and ISOP	12,691	44	42				86
Net Income				11,611			11,611
Cash Dividends:							
Common Stock				(3,101)			(3,101)
Preferred Stock—$7.00 per share				(7)			(7)
—$9.375 per share				(23)			(23)
—$8.625 per share				(25)			(25)
—$7.32 per share				(878)			(878)
BALANCE, December 31, 2001	**5,701,010**	**$19,004**	**$74,581**	**$ 8,070**	**15,856**	**($378)**	**$101,277**

During 2000, the Compensation Program for Officers and Certain Key Management personnel, that authorized payment of cash, restricted and unrestricted stock grants based on corporate performance, was replaced with the stock incentive plan discussed above. Approximately 1,262 restricted shares, issued during 1996 and 1997, remain unvested under this program at December 31, 2001.

Changes in common stock equity for the years ended December 31, 2001, 2000 and 1999 are as shown above.

Dividend Restrictions

Certain restrictions on the payment of cash dividends on common stock are contained in the Company's indentures relating to long-term debt and in the Restated Articles of Association. Under the most restrictive of such provisions, approximately $8.0 million of retained earnings were free of restrictions at December 31, 2001.

The properties of the Company include several hydroelectric projects licensed under the Federal Power Act, with license expiration dates ranging from 2001 to 2025. At December 31, 2001, $168,000 of retained deficit had been appropriated as excess earnings on hydroelectric projects as required by Section 10(d) of the Federal Power Act.

D Preferred Stock

The holders of the preferred stock are entitled to specific voting rights with respect to certain types of corporate actions. They are also entitled to elect the smallest number of directors necessary to constitute a majority of the Board of Directors in the event of preferred stock dividend arrearages equivalent to or exceeding four quarterly dividends. Similarly, the holders of the preferred stock are entitled to elect two directors in the event of default in any purchase or sinking fund requirements provided for any class of preferred stock.

Certain classes of preferred stock are subject to annual purchase or sinking fund requirements. The sinking fund requirements are mandatory. The purchase fund requirements are mandatory, but holders may elect not to accept the purchase offer. The redemption or purchase price to satisfy these requirements may not exceed $100 per share plus accrued dividends. All shares redeemed or purchased in connection with these requirements must be canceled and may not be reissued. The annual purchase and sinking fund requirements for the year 2002 for certain classes of preferred stock are as follows:

Class:	Purchase and Sinking Fund Due Dates	Shares to Retire
4.750%, Class B	December 1	300
7.000%, Class C	December 1	450
9.375%, Class D, Series 1	December 1	1,600

Under the Restated Articles of Association relating to Redeemable Cumulative Preferred Stock, the annual aggregate amount of purchase and sinking fund requirements for the next five years are $235,000 for 2002, $75,000 each for 2003 and 2004, $70,000 for 2005 and $105,000 thereafter.

Certain classes of preferred stock are redeemable at the option of the Company or, in the case of voluntary liquidation, at various prices on various dates. The prices include the par value of the issue plus any accrued dividends and an early redemption premium. The redemption premium for Class B, C and D, Series 1, is $1.00 per share. See Note M, Subsequent Events, for additional information concerning the early redemption of preferred stock.

E Short-Term Debt

The Company has a $15.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by KeyBank National Association,("KeyBank") expiring June 2002 (the "Fleet-Key Agreement"). The Fleet-Key Agreement replaced a similar agreement with Fleet and Citizens Bank of Massachusetts (the "Fleet agreement") in the amount of $15.0 million, with borrowings outstanding of $500,000, with a weighted average rate of 9.5 percent, at December 31, 2000. There was $0.0 outstanding on the Fleet-Key Agreement at December 31, 2001. There was no non-utility short-term debt outstanding at December 31, 2001 or 2000.

The Fleet-Key Agreement is unsecured, and requires the Company to certify on a quarterly basis that it has not suffered a "material adverse change". Similarly, as a condition to further borrowings, the Company must certify that no event has occurred or failed to occur that has had or would reasonably be expected to have a materially adverse effect on the Company since the date of the last borrowing under this agreement. The Fleet-Key Agreement allows the Company to continue to borrow until such time that:

- a "material adverse effect" has occurred; or
- the Company no longer complies with all other provisions of the agreement, in which case further borrowing will not be permitted; or
- there has been a "material adverse change", in which case the banks may declare the Company in default.

On September 20, 2000, we established a $15.0 million revolving credit agreement ("KeyBank agreement") with KeyBank National Association ("KeyBank"). 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. 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 indebtedness issued under the Keybank agreement. The payment made by EE was returned to EE along with accrued interest on September 11, 2001. The KeyBank agreement expired on September 19, 2001. There was $15.0 million outstanding on the KeyBank agreement at December 31, 2000.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2002.

During the first quarter of 2001, Moody's Investors Service and Fitch upgraded the Company's first mortgage bond and preferred stock ratings. The rating action reflected the rating agencies' earnings and cash flow expectations for the Company following the VPSB Order on the Company's 1998 retail rate case (the "Settlement Order") issued January 23, 2001. See Note I-5, Rate Matters, for further information regarding the settlement of the Company's 1998 retail rate case with the Department and the VPSB.

F Long-Term Debt

Substantially all of the property and franchises of the Company are subject to the lien of the indenture under which first mortgage bonds have been issued. The weighted average rate on long term borrowings outstanding was 7.1 percent and 7.6 percent at December 31, 2001 and 2000, respectively. The annual sinking fund requirements (excluding amounts that may be satisfied by property additions) and long-term debt maturities for the next five years are:

	Sinking Fund and Maturities (In thousands)
2002	$ 9,700
2003	21,700
2004	1,700
2005	—
2006	14,000
Thereafter	37,000
Total long-term debt	$84,100

The Company executed and delivered a $12.0 million, unsecured two-year loan agreement with Fleet, joined by KeyBank, as part of the Fleet-Key Agreement for revolving credit. On July 27, 2001, the VPSB approved the financing arrangement, and the loan was made on August 24, 2001. The Company used this facility, along with proceeds from the maturing KeyBank certificate of deposit, to terminate the KeyBank agreement and repay the $15.0 million it received from EE pursuant to the power supply option agreement discussed above. At December 31, 2001, there was $12.0 million outstanding under the two-year loan agreement.

See Note M, Subsequent Events, for information about a proposed redemption of certain first mortgage bonds.

G Income Taxes

Utility

The Company accounts for income taxes using the liability method. This method accounts for deferred income taxes by applying statutory rates to the differences between the book and tax bases of assets and liabilities.

The regulatory tax assets and liabilities represent taxes that will be collected from or returned to customers through rates in future periods. As of December 31, 2001 and 2000, the net regulatory assets were $1,096,000 and $1,908,000, respectively, and included in Other Deferred Charges on the Company's consolidated balance sheets.

The temporary differences which gave rise to the net deferred tax liability at December 31, 2001 and December 31, 2000, were as follows:

	At December 31, 2001	2000
	(In thousands)	
Deferred Tax Assets		
Contributions in aid of construction	$10,435	$10,018
Deferred compensation and postretirement benefits	4,382	4,122
Self-insurance and other reserves	—	—
Other	5,525	1,958
	20,342	16,098
Deferred Tax Liabilities		
Property-related	39,518	38,648
Demand side management	2,059	1,810
Deferred purchased power costs	1,450	84
Pine Street reserve	855	571
Other	219	629
	44,101	41,742
Net accumulated deferred income tax liability	$23,759	$25,644

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

	Years ended December 31, 2001	2000	1999
		(In thousands)	
Net change in deferred income tax liability	($1,885)	$443	$1,812
Change in income tax related regulatory assets and liabilities	(1,149)	184	176
Changes in alternative minimum tax credit	—	—	—
Deferred income tax expense (benefit)	($3,034)	$627	$1,988

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

	Years ended December 31, 2001	2000	1999
		(In thousands)	
Current federal income taxes	$ 7,846	($ 786)	($ 339)
Current state income taxes	2,418	(249)	(125)
Total current income taxes	10,264	(1,035)	(464)
Deferred federal income taxes	(2,296)	461	1,479
Deferred state income taxes	(738)	166	509
Total deferred income taxes	(3,034)	627	1,988
Investment tax credits—net	(282)	(283)	(282)
Income tax provision (benefit)	$ 6,948	($ 691)	$1,242

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

	Years ended December 31, 2001	2000	1999
		(Dollars in thousands)	
Income (loss) before income taxes and preferred dividends	$18,559	($6,531)	($1,821)
Federal statutory rate	35.0%	34.0%	34.0%
Computed "expected" federal income taxes	6,496	(2,221)	(619)
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation	45	83	92
Dividends received and paid credit	(440)	(435)	(485)
AFUDC–equity funds	(72)	(33)	(5)
Amortization of ITC	(282)	(282)	(282)
State tax (benefit)	1,705	(83)	383
Excess deferred taxes	(60)	(60)	(60)
Taxes attributable to subsidiaries	63	2,213	2,271
Other	(506)	127	(53)
Total federal and state income tax (benefit)	$ 6,948	($ 691)	$ 1,242
Effective combined federal and state income tax rate	37.4%	10.6%	(68.2)%

Non-Utility

The Company's non-utility subsidiaries, excluding NWR, had accumulated deferred income taxes of approximately $2,000 on their balance sheets at December 31, 2001, attributable to depreciation timing differences.

The components of the provision for the income tax expense (benefit) for the non-utility operations are:

	Years ended December 31, 2001	2000	1999
		(In thousands)	
State income taxes	$—	$ 7	$ 99
Federal income taxes	(1)	21	310
Income tax expense (benefit)	($ 1)	$28	$409

The effective combined federal and state income tax rate for the continuing non-utility operations was approximately 40.0 percent for each of the years ended December 31, 2001, 2000 and 1999. See Note L for income tax information on the discontinued operations of NWR.

H Pension and Retirement Plans

The Company has a defined benefit pension plan covering substantially all of its employees. The retirement benefits are based on the employees' level of compensation and length of service. The Company's policy is to fund all accrued pension costs. The Company records annual expense and accounts for its pension plan in accordance with Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions. The Company provides certain health care benefits for retired employees and their dependents. Employees become eligible for these benefits if they reach retirement age while working for the Company. The Company accrues the cost of these benefits during the service life of covered employees. The pension plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities.

Accrued postretirement health care expenses are recovered in rates to the extent those expenses are funded. In order to maximize the tax-deductible contributions that are allowed under IRS regulations, the Company amended its pension plan to establish a 401-h sub-account and separate VEBA trusts for its union and non-union employees. The VEBA plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities. The following provides a reconciliation of benefit obligations, plan assets, and funded status of the plans as of December 31, 2001 and 2000.

	At and for the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
	(In thousands)			
Change in projected benefit obligation:				
Projected benefit obligation as of prior year end	$23,332	$22,444	$14,947	$11,955
Service cost	537	655	241	216
Interest cost	1,737	1,658	1,043	1,049
Participant contributions	—	—	151	—
Change in actuarial assumptions	367	—	—	2,328
Actuarial (gain) loss	1,650	513	1,021	73
Benefits paid	(1,670)	(1,707)	(912)	(674)
Administrative expense	(58)	(231)	—	—
Projected benefit obligation as of year end	$25,895	$23,332	$16,491	$14,947
Change in plan assets:				
Fair value of plan assets as of prior year end	$27,760	$31,477	$10,944	$11,062
Administrative expenses paid	(58)	(231)	—	—
Participant contributions	—	—	151	—
Employer contributions	—	—	761	673
Actual return on plan assets	(1,691)	(1,779)	(928)	(118)
Benefits paid	(1,670)	(1,707)	(912)	(673)
Fair value of plan assets as of year end	$24,341	$27,760	$10,016	$10,944
Funded status as of year end	($1,554)	$ 4,428	($6,475)	($4,003)
Unrecognized transition obligation (asset)	(241)	(406)	3,608	3,936
Unrecognized prior service cost	986	766	(519)	(577)
Unrecognized net actuarial gain	(892)	(6,848)	2,711	(130)
Accrued benefits at year end	($1,701)	($2,060)	($ 675)	($ 774)

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31, 2001, 2000, and 1999 were $340,000, $346,000, and $556,000, respectively, under this plan. This plan is funded in part through insurance contracts.

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

	For the years ended December 31,					
	Pension Benefits			Other Postretirement Benefits		
	2001	2000	1999	2001	2000	1999
	(In thousands)					
Service cost	$ 537	$ 655	$ 620	$ 241	$ 216	$ 240
Interest cost	1,737	1,658	1,780	1,043	1,049	855
Expected return on plan assets	(2,379)	(2,580)	(2,721)	(892)	(940)	(834)
Amortization of transition asset	(164)	(164)	(196)	—	—	—
Amortization of net gain from earlier periods	—	—	—	—	—	—
Amortization of prior service cost	147	121	128	(58)	(58)	(60)
Amortization of the transition obligation	—	—	—	328	328	340
Recognized net actuarial gain	(237)	(474)	(196)	—	—	(19)
Special termination benefit	—	—	3,122	—	—	888
Regulatory deferral	—	—	(3,122)	—	—	(888)
Net periodic benefit cost	($ 359)	($ 784)	($ 585)	$ 662	$ 595	$ 522

Assumptions used to determine postretirement benefit costs and the related benefit obligation were:

	For the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
Weighted average assumptions as of year end:				
Discount rate	7.50%	7.50%	7.00%	7.50%
Expected return on plan assets	9.00%	9.00%	8.50%	8.50%
Rate of compensation increase	4.50%	4.50%	4.25%	4.50%
Medical inflation	—	—	8.00%	6.00%

For measurement purposes, an 8.0 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2001. This rate of increase gradually reduces to 6.0 percent in 2005. The medical trend rate assumption has a significant effect on the amounts reported. For example, increasing the assumed health care cost trend rate by one percentage point for all future years would increase the accumulated postretirement benefit obligation as of December 31, 2001 by $2.4 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2001 by $208,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2001 by $1.9 million, and the total of the service and interest cost components of net periodic postretirement cost for 2001 by $165,000.

In 1999, the Company deferred special termination pension benefit costs of $3,122,000 due to an early retirement program and other employee separation activities. Curtailment and settlement gains of $2.3 million are included in the special termination pension benefit cost. Also in 1999, the Company deferred special termination postretirement benefit costs of $888,000 due to an early retirement program. Management believes that the amounts deferred are probable of recovery.

I Commitments and Contingencies

1. Industry Restructuring

The electric utility business is being subjected to rapidly increasing competitive pressures stemming from a combination of trends. Certain states, including all the New England states except Vermont, have enacted legislation to allow retail customers to choose their electric suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems. Recent power supply management difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards de-regulation in Vermont. There can be no assurance that any potential future restructuring plan ordered by the VPSB, the courts, or through legislation will include a mechanism that would allow for full recovery of our stranded costs and include a fair return on those costs as they are being recovered.

2. Environmental Matters

The electric industry typically uses or generates a range of potentially hazardous products in its operations. The Company 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 those requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site. The Company maintains an environmental compliance and monitoring program that includes employee training, regular inspection of Company facilities, research and development projects, waste handling and spill prevention procedures and other activities.

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. The Company has been notified by the Environmental Protection Agency ("EPA") that it is one of several potentially responsible parties ("PRPs") for cleanup of the Pine Street Barge Canal 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 EPA, the State of Vermont, and other parties over terms of a Consent Decree that covers claims addressed in the earlier negotiations and implementation of the selected remedy. In November 1999, the Consent Decree was filed in the federal district court. The Consent Decree addresses claims by the EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site.

As of December 31, 2001, the Company's total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $25.2 million. This includes those 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, and more costly, proposals for the site, as well as litigation and related costs necessary to obtain settlements with insurers and other PRP's 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 the EPA and State orders that resulted in funding response activities at the site, and to reimburse 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 33 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. 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 Barge Canal 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". The VPSB Settlement Order regarding the Company's 1998 retail rate case did not change the status of Pine Street cost recovery.

Clean Air Act

The Company purchases most of its power supply from other utilities and does not anticipate that it will incur any material direct costs as a result of the Federal Clean Air Act or proposals to make more stringent regulations under that Act.

3. Operating Leases

The Company terminated an operating lease for its corporate headquarters building and two of its service center buildings in the first quarter of 1999. The Company sold its corporate headquarters building in 1999, but retained ownership of the two service centers.

4. Jointly-Owned Facilities

The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2001, as follows:

	Ownership Interest	Share of Capacity	Utility Plant	Accumulated Depreciation
	(In %)	(In MW)	(In thousands)	
Highgate	33.8	67.6	$10,299	$4,388
McNeil	11.0	5.9	8,866	4,779
Stony Brook (No. 1)	8.8	31.0	10,339	7,636
Wyman (No. 4)	1.1	6.8	1,980	1,255
Metallic Neutral Return	59.4	—	1,563	681

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

The Company's share of expenses for these facilities is reflected in the Consolidated Statements of Income. Each participant in these facilities must provide its own financing.

5. Rate Matters

Retail Rate Cases

The Company reached a final settlement agreement with the Department in its 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-Québec Vermont Joint Owners ("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 replaces 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 can be utilized 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 the 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 earned approximately $30,000 in excess of its allowed rate of return during 2001 before writing off regulatory assets in the same amount.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions:

- The Company and customers shall share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share; and
- The Company's further investment in non-utility operations is restricted.

During 2001, the VPSB opened a review of "special" or off-tariff contracts, which require specific VPSB approval. As a result of the review, the Company became aware of one special contract for station service at the McNeil generating facility which had not received prior VPSB approval. The Company expects that a minor penalty will be levied by the VPSB for this omission, but such penalty could be material.

6. Deferred Charges Not Included in Rate Base

The Company has incurred and deferred approximately $3.9 million in costs for tree trimming, storm damage and federal regulatory commission work of which $1.2 million is being amortized on an annual basis. Currently, the Company amortizes such costs based on amounts being recovered and does not receive a return on amounts deferred. Management expects to seek and receive ratemaking treatment for these costs in future filings.

The Settlement Order directed the Company to write-off deferred charges applicable to the state regulatory commission of $3.2 million as part of the rate case agreement with the Department. The charge is included in other operating expense for the year ended December 31, 2000. The Settlement Order requires the remaining balance and future expenditures of deferred regulatory commission charges be amortized over seven years.

7. Competition

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase an existing hydro-generation facility from a third party, and the associated distribution plant owned by the Company within Rockingham. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue reimbursement such that our remaining customers do not subsidize Rockingham.

8. Other Legal Matters

The Company is involved in legal and administrative proceedings in the normal course of business and does not believe that the ultimate outcome of these proceedings will have a material effect on the financial position or the results of operations of the Company.

J Obligations Under Transmission Interconnection Support Agreement

Agreements executed in 1985 among the Company, VELCO and other NEPOOL members and Hydro-Québec provided for the construction of the second phase (Phase II) of the interconnection between the New England electric systems and that of Hydro-Québec. Phase II expands the Phase I facilities from 690 megawatts to 2,000 megawatts and provides for transmission of Hydro-Québec power from the Phase I terminal in northern New Hampshire to Sandy Pond, Massachusetts. Construction of Phase II commenced in 1988 and was completed in late 1990. The Company is entitled to 3.2 percent of the Phase II power-supply benefits. Total construction costs for Phase II were approximately $487 million. The New England participants, including the Company, have contracted to pay monthly their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. As a supporting participant, the Company must make support payments under thirty-year agreements. These support agreements meet the capital lease accounting requirements. At December 31, 2001, the present value of the Company's obligation is approximately $6.0 million.

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

	Years ending December 31,
	(In thousands)
2002	$ 426
2003	425
2004	426
2005	425
2006	426
Total for 2007–2015	3,831
Total	$5,959

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company and New England Hydro-Transmission Corporation, subsidiaries of New England Electric System, in which certain of the Phase II participating utilities, including the Company, own equity interests. The Company holds approximately 3.2 percent of the equity of the corporations owning the Phase II facilities.

K Long-Term Power Purchases

1. Unit Purchases

Under long-term contracts with various electric utilities in the region, the Company is purchasing certain percentages of the electrical output of production plants constructed and financed by those utilities. Such contracts obligate the Company to pay certain minimum annual amounts representing the Company's proportionate share of fixed costs, including debt service requirements whether or not the production plants are operating. The cost of power obtained under such long-term contracts, including payments required when a production plant is not operating, is reflected as "Power Supply Expenses" in the accompanying Consolidated Statements of Income.

Information (including estimates for the Company's portion of certain minimum costs and ascribed long-term debt) with regard to significant purchased power contracts of this type in effect during 2001 follows:

	Stony Brook	Vermont Yankee
	(Dollars in thousands)	
Plant capacity	352.0 MW	531.0 MW
Company's share of output	4.40%	17.90
Contract period expires:	2006	2012
Company's annual share of:		
Interest	$ 161	$ 1,932
Other debt service	401	—
Other capacity	527	26,819
Total annual capacity	$1,089	$28,751
Company's share of long-term debt	$2,797	$10,667

2. Hydro-Québec System Power Purchase and Sale Commitments

Under various contracts, the details of which are described in the table below, the Company purchases capacity and associated energy produced by the Hydro-Québec system. Such contracts obligate the Company to pay certain fixed capacity costs whether or not energy purchases above a minimum level set forth in the contracts are made. Such minimum energy purchases must be made whether or not other, less expensive energy sources might be available. These contracts are intended to complement the other components in the Company's power supply to achieve the most economic power-supply mix reasonably available. There are specific step-up provisions that provide that in the event any VJO contract member fails to meet its obligation under the contract with Hydro-Québec, the remaining VJO participants, including the Company, will "step-up" to the defaulting participants share on a prorated basis.

The Company's current purchases pursuant to the contract with Hydro-Québec entered into December 4, 1987 (the "1987 Contract") are as follows: (1) Schedule B-68 megawatts of firm capacity and associated energy to be delivered at the Highgate interconnection for twenty years beginning in September 1995; and (2) Schedule C3-46 megawatts of firm capacity and associated energy to be delivered at interconnections to be determined at any time for 20 years, which began in November 1995.

Hydro-Québec also has the right to reduce the load factor from 75 percent to 65 percent under the 1987 Contract a total of three times over the life of the contract. The Company can delay such reduction by one year under the same contract. During 2001, Hydro-Québec exercised the first of these options for 2002, and the Company delayed the effective date of this exercise until 2003. The Company estimates that the net cost of Hydro-Québec's exercise of its option will increase power supply expense during 2003 by approximately $0.4 million.

During 1994, the Company negotiated an arrangement with Hydro-Québec that reduced the cost impacts associated with the purchase of Schedules B and C3 under the 1987 Contract, over the November 1995 through October 1999 period (the "July 1994 Agreement"). Under the July 1994 Agreement, the Company, in essence, will take delivery of the amounts of energy as specified in the 1987 Contract, but the associated fixed costs will be significantly reduced from those specified in the 1987 Contract.

As part of the July 1994 Agreement, we were obligated to purchase $4.0 million (in 1994 dollars) worth of research and development work from Hydro-Québec over a period ending October 1999, which has since been extended, and made an additional $6.5 million (plus accrued interest) payment to Hydro-Québec in 1995. Hydro-Québec retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Quebec. The period for completing the research and development purchase was subsequently extended to March 2001.

During the first year of the July 1994 Agreement (the period from November 1995 through October 1996), the average cost per kilowatt-hour of Schedules B and C3 combined was cut from 6.4 to 4.2 cents per kilowatt-hour, a 34 percent or $16 million cost reduction. Over the period from November 1996 through December 2000 and accounting for the payments to Hydro-Québec, the combined unit costs were lowered from 6.5 to 5.9 cents per kilowatt-hour, reducing unit costs by 10 percent and saving $20.7 million in nominal terms.

All of the Company's contracts with Hydro-Québec call for the delivery of system power and are not related to any particular facilities in the Hydro-Québec system. Consequently, there are no identifiable debt-service charges associated with any particular Hydro-Québec facility that can be distinguished from the overall charges paid under the contracts.

A summary of the Hydro-Québec contracts through the July 1994 Agreement, including historic and projected charges for the years indicated, follows:

	The 1987 Contract Schedule B	Schedule C3
	(Dollars in thousands except per KWH)	
Capacity Acquired	68 MW	46 MW
Contract Period	1995–2015	1995–2015
Minimum Energy Purchase (annual load factor)	75%	75%
Annual Energy Charge 2001	$11,891	$ 8,025
Estimated 2002–2015	$13,261 (1)	$ 9,062 (1)
Annual Capacity Charge 2001	$16,850	$11,613
Estimated 2002–2015	$17,103 (1)	$11,687 (1)
Average Cost per KWH 2001	$ 0.063	$ 0.064
Estimated 2002–2015	$ 0.066 (2)	$ 0.066 (2)

(1) Estimated average. Includes load factor reduction to 65 percent in 2003.
(2) Estimated average in nominal dollars levelized over the period indicated.
Includes amortization of payments to Hydro-Québec for the July 1994 Agreement.

Under a power supply arrangement executed in January 1996 ("9601"), we received payments from Hydro-Québec of $3.0 million in 1996 and $1.1 million in 1997. Under 9601, the Company was required to shift up to 40 megawatts of its Schedule C3 deliveries to an alternate transmission path and use the associated portion of the NEPOOL/Hydro-Québec interconnection facilities to purchase power for the period from September 1996 through June 2001 at prices that varied based upon conditions in effect when the purchases were made. The 9601 arrangement also provided for minimum payments by the Company to Hydro-Québec for the periods in which power was not purchased under the arrangement. This arrangement allowed Hydro-Québec to curtail energy deliveries should it need to use certain resources to supplement available supply. During the last three months of 2000, Hydro-Québec curtailed energy deliveries. Under a separate arrangement established on December 5, 1997 (the "9701 arrangement"), Hydro-Québec provided a payment of $8.0 million to the Company in 1997. In return for this payment, the Company provided Hydro-Québec an ongoing option for the purchase of power. Commencing April 1, 1998, and effective through October 2015, Hydro-Québec can exercise an option to purchase up to 52,500 MWh ("option A") on an annual basis, at energy prices established in accordance with the 1987 Contract. The cumulative amount of energy purchased under the 9701 arrangement shall not exceed 950,000 MWh. Hydro-Québec's option to curtail energy deliveries pursuant to the 1987 Contract and the July 1994 Agreement may be exercised in addition to these purchase options.

Over the same period, Hydro-Québec can exercise an option on an annual basis to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy price. Hydro-Québec can purchase no more than 200,000 MWh in any given contract year ending October 31. As of December 31, 2001, Hydro-Québec had purchased or called to purchase 432,000 MWh under option B.

In 2001, Hydro-Québec exercised option A and option B, calling for deliveries to third parties at a net expense to the Company of approximately $7.6 million, including capacity charges.

In 2000, Hydro-Québec called for deliveries to third parties at a net cost to the Company of approximately $14.0 million (including the cost of the January and February 2001 calls and related financial positions), which was due to higher energy replacement costs. The 9701 arrangement costs are currently being recovered in rates on an annual basis. The VPSB, in the Settlement Order stated, "The record does not demonstrate that any other New England utility foresaw the extent and degree of volatility that has developed in the New England wholesale power markets. Absent that volatility, the 97-01 Agreement would not have had adverse effects." In conjunction with the Settlement Order, Hydro-Québec committed to the Department that it would not call any energy under option B of the 9701 arrangement during the contract year ending October 31, 2002. In 1999, Hydro-Québec called for deliveries to third parties at a net cost to the Company of approximately $6.3 million. The Company's estimate of the fair value of the future net cost for the 9701 arrangement, which is dependent upon the timing of any exercise of options, and the market price for replacement power, is approximately $25.7 million. Future estimates could change by a material amount.

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-Québec for its failure to deliver electricity pursuant to the VJO/Hydro-Québec 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-Québec and partially with the VJO. In the decision, the Tribunal concluded (i) the VJO/Hydro-Québec power supply contract remains in effect, and Hydro-Québec 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-Québec is required to return certain capacity payments to the VJO.

On July 23, 2001, the Company received approximately $3.2 million representing its share of refunded capacity payments from Hydro-Québec. These proceeds reduced related deferred assets. At December 31, 2001, the deferred balance of unrecovered arbitration costs is approximately $1.2 million. We believe it is probable that this balance will ultimately be recovered in rates.

3. Morgan Stanley Agreement

On February 11, 1999, the Company entered into a contract with MS. In January 2001, the MS contract was modified and extended to December 31, 2003. The contract provides us a means of managing price risks associated with changing fossil fuel prices. On a daily basis, and at MS's discretion, the Company will sell power to MS from either (i) all or part of our portfolio of power resources at predefined operating and pricing parameters or (ii) any power resources available to the Company, provided that sales of power from sources other than Company-owned generation comply with the predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements. MS is also responsible for scheduling supply resources. The Company remains responsible for resource performance and availability. MS provides no coverage against major unscheduled outages.

The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. We anticipate that arrangements we make to manage power supply risks will be on average more costly than the expected cost of fuel during the periods being hedged because these arrangements would typically incorporate a risk premium.

L Discontinued Operations

The Company sold or otherwise disposed of a significant portion of the operations and assets of NWR, which owned and invested in energy generation, energy efficiency, and wastewater treatment projects. The provisions for loss from discontinued operations reflect management's current estimate. Assets remaining include two wind power partnership investments, a note receivable from a regional hydro-power project, notes receivable and equity investments with two wastewater treatment projects, one of which has risk factors that include the outcome of warranty litigation, and future cash requirements necessary to minimize costs of winding down wastewater operations. Several municipalities using wastewater treatment equipment have commenced or threatened litigation. The ultimate loss remains subject to the disposition of remaining assets and liabilities, and could exceed the amounts recorded. The following illustrates the results and financial statement impact of NWR during and at the periods shown:

	2001	2000	1999
	(In thousands except per share)		
Revenues	$ 156	$ 1,546	$ 2,296
Net loss from operations	—	—	(603)
Provisions for loss on disposal and future operating losses	(182)	(6,549)	(6,676)
Net loss	($182)	($6,549)	($7,279)
Net loss per share–basic	($0.03)	($1.19)	($ 1.36)
Proceeds from sales	$1,425	$6,000	$ —
Total assets	$3,697	$8,411	$19,395

Income taxes for NWR for the years ended December 31, 2001, 2000 and 1999 are summarized as:

	Years ended December 31, 2001	2000	1999
	(In thousands)		
State income taxes	($175)	($1,064)	($ 281)
Federal income taxes	(550)	(3,349)	(1,371)
Investment tax credits	—	—	—
Income tax expense (benefit)	($725)	($4,413)	($1,652)

M Subsequent Events

On February 14, 2002, the Company notified holders of its 10 percent First Mortgage Bonds due June 1, 2004, that it would redeem all of those bonds in March 2002. Bonds outstanding for the issue total $5.1 million and are subject to annual sinking fund requirements of $1.7 million. The call premium will be approximately $0.1 million.

On March 4, 2002, the Vermont Department of Public Service announced its endorsement of the proposed sale of the Vermont Yankee nuclear plant to Entergy Nuclear Corp., as discussed in Note B.

On March 12, 2002, the Company purchased $10.0 million of the Company's 7.32 percent, Class E, Series 1 preferred stock outstanding for approximately $10.1 million.

N Quarterly Financial Information (Unaudited)

The following quarterly financial information, in the opinion of management, includes all adjustments necessary to a fair statement of results of operations for such periods. Variations between quarters reflect the seasonal nature of the Company's business and the timing of rate changes.

	2001 Quarter Ended March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$74,796	$67,471	$76,051	$65,146	$283,464
Operating income (loss)	4,575	4,275	4,573	3,036	16,459
Net income (loss) from continuing operations	$ 2,914	$ 2,884	$ 3,387	$ 1,675	$ 10,860
Net loss from discontinued operations	—	(150)	—	(32)	(182)
Net income (loss) applicable to common stock	$ 2,914	$ 2,734	$ 3,387	$ 1,643	$ 10,678
Basic earnings (loss) per share from:					
Continuing operations	$ 0.52	$ 0.52	$ 0.60	$ 0.29	$ 1.93
Discontinued operations	—	(0.03)	—	—	(0.03)
Basic earnings per share	$ 0.52	$ 0.49	$ 0.60	$0.29	$ 1.90
Weighted average common shares outstanding	5,588	5,615	5,644	5,672	5,630
Diluted earnings (loss) per share from:					
Continuing operations	$ 0.51	$ 0.50	$ 0.58	$ 0.29	$ 1.88
Discontinued operations	—	(0.03)	—	—	(0.03)
Diluted earnings (loss) per share:	$ 0.51	$ 0.47	$ 0.58	$ 0.29	$ 1.85
Weighted average common and common equivalent shares outstanding	5,741	5,777	5,814	5,848	5,789

	2000 Quarter Ended March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$67,712	$61,927	$78,143	$69,544	$277,326
Operating income (loss)	4,613	(2,997)	3,271	373	5,260
Net income (loss) from continuing operations	$ 3,449	($4,375)	$ 1,961	($1,340)	($ 305)
Net loss from discontinued operations	—	(1,530)	—	(5,019)	(6,549)
Net income (loss) applicable to common stock	$ 3,449	($5,905)	$ 1,961	($6,359)	($ 6,854)
Earnings (loss) per share from:					
Continuing operations	$ 0.63	($ 0.80)	$ 0.36	($ 0.25)	($ 0.06)
Discontinued operations	—	(0.28)	—	(0.91)	(1.19)
Basic and diluted	$ 0.63	($ 1.08)	$ 0.36	($ 1.16)	($ 1.25)
Weighted average common shares outstanding	5,437	5,472	5,505	5,551	5,491

	1999 Quarter Ended March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$59,018	$59,535	$68,478	$64,017	$251,048
Operating income	3,906	977	1,412	1,651	7,946
Net income (loss) from continuing operations	$ 3,170	($ 412)	($ 115)	$ 418	$ 3,061
Net loss from discontinued operations	(522)	(81)	(4,592)	(2,084)	(7,279)
Net income (loss) applicable to common stock	$ 2,648	($ 493)	($4,707)	($1,666)	($ 4,218)
Earnings (loss) per share from:					
Continuing operations	$ 0.60	($ 0.08)	($ 0.02)	$ 0.07	$ 0.57
Discontinued operations	(0.10)	(0.02)	(0.85)	(0.39)	(1.36)
Basic and diluted	$ 0.50	($ 0.10)	($ 0.88)	($ 0.31)	($ 0.79)
Weighted average common shares outstanding	5,318	5,344	5,374	5,291	5,361

Report of Independent Public Accountants

To the Board of Directors of
Green Mountain Power Corporation:

We have audited the accompanying consolidated balance sheets and consolidated capitalization data of Green Mountain Power Corporation (a Vermont corporation) and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and its subsidiaries as of December 31, 2001 and 2000, and the consolidated results of its operations and cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note A to the financial statements, effective January 1, 2001, the company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Arthur Andersen LLP

Boston, Massachusetts
March 12, 2002

Consolidated Statements of Income

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

In thousands, except per share amounts	2001	2000	1999
Operating Revenues			
Residential	$ 69,727	$ 69,832	$ 67,061
Lease	—	—	—
Total residential and lease	69,727	69,832	67,061
Commercial and industrial–small	73,729	70,382	68,004
Commercial and industrial–large	51,638	45,729	43,518
Sales for resale	83,805	88,333	68,305
Other	4,565	3,050	4,160
Total operating revenues	283,464	277,326	251,048
Operating Expenses			
Power Supply			
Vermont Yankee Nuclear Power Corporation	30,114	34,813	34,987
Company-owned generation	4,742	7,777	5,582
Purchases from others	166,209	168,947	142,699
Other operating	15,924	17,644	17,582
Transmission	14,130	14,237	10,800
Maintenance	7,108	6,633	6,728
Depreciation and amortization	14,294	15,304	16,187
Taxes other than income	7,536	7,402	7,295
Income taxes	6,948	(691)	1,242
Total operating expenses	267,005	272,066	243,102
Operating income	16,459	5,260	7,946
Other Income			
Equity in earnings of affiliates and non-utility operations	2,253	2,495	2,919
Allowance for equity funds used during construction	210	284	134
Other income and deductions, net	(90)	(73)	400
Total other income	2,373	2,706	3,453
Income before interest charges	18,832	7,966	11,399
Interest Charges			
Long-term debt	6,073	6,499	6,716
Other	1,154	986	558
Allowance for borrowed funds used during construction	(188)	(228)	(91)
Total interest charges	7,039	7,257	7,183
Income (loss) before preferred dividends and discontinued operations	11,793	709	4,216
Dividends on preferred stock	933	1,014	1,155
Income (loss) from continuing operations	10,860	(305)	3,061
Net income (loss) from discontinued segment operations	—	—	(603)
Loss on disposal, including provisions for operating losses during phaseout period	(182)	(6,549)	(6,676)
Net Income (Loss) Applicable to Common Stock	$ 10,678	($ 6,854)	($ 4,218)
Common Stock Data			
Basic earnings (loss) per share from discontinued operations	($ 0.03)	($ 1.19)	($ 1.36)
Basic earnings (loss) per share from continuing operations	1.93	(0.06)	0.57
Basic earnings (loss) per share	$ 1.90	($ 1.25)	($ 0.79)
Diluted earnings per share from discontinued operations	($ 0.03)	($ 1.19)	($1.36)
Diluted earnings per share from continuing operations	1.88	(0.06)	0.57
Diluted earnings per share	$ 1.85	($ 1.25)	($ 0.79)
Cash dividends declared per share	$ 0.55	$ 0.55	$ 0.55
Weighted average shares outstanding–basic	5,630	5,491	5,361
Weighted average shares outstanding–diluted	5,789	5,491	5,361

1998	1997	1996	1995	1994	1993	1992	1991
$ 61,697	$ 61,423	$ 60,598	$ 55,434	$ 50,966	$ 49,391	$ 45,658	$ 42,298
—	—	—	—	—	419	1,883	2,181
61,697	61,423	60,598	55,434	50,966	49,810	47,541	44,479
61,816	58,700	56,530	51,245	48,374	47,310	45,552	43,030
40,201	37,841	36,704	32,616	31,381	31,569	31,775	29,721
16,529	17,847	20,667	17,541	13,521	14,441	17,258	23,663
4,061	3,512	4,510	4,708	3,955	4,123	3,114	2,662
184,304	179,323	179,009	161,544	148,197	147,253	145,240	143,555
32,910	32,817	30,596	30,222	30,300	29,785	29,230	27,464
6,412	5,327	3,330	3,786	3,113	3,150	3,804	4,946
81,706	62,222	66,320	53,915	45,777	46,066	41,878	45,951
21,291	16,780	17,615	18,120	17,296	17,353	17,239	15,934
9,389	11,122	10,833	9,874	10,374	10,775	11,103	11,661
5,190	4,785	4,463	4,210	4,465	4,352	4,692	4,340
16,059	16,359	16,280	14,116	10,683	8,572	8,065	7,046
7,242	7,205	6,982	6,428	6,277	6,125	5,902	5,677
(1,367)	7,191	6,463	5,578	5,395	6,249	6,915	6,022
178,832	163,808	162,882	146,249	133,680	132,427	128,828	129,041
5,472	15,515	16,127	15,295	14,517	14,826	16,412	14,514
2,058	285	1,564	2,131	2,287	2,239	2,305	2,888
104	357	175	27	263	273	186	225
(549)	789	175	94	306	19	(105)	(66)
1,613	1,431	1,914	2,252	2,856	2,531	2,386	3,047
7,085	16,946	18,041	17,547	17,373	17,357	18,798	17,561
6,991	7,274	6,872	6,546	6,868	6,539	6,542	6,064
1,016	691	994	1,427	867	646	479	1,039
(131)	(315)	(468)	(547)	(539)	(357)	(202)	(131)
7,876	7,650	7,398	7,426	7,196	6,828	6,819	6,972
(791)	9,296	10,643	10,121	10,177	10,529	11,979	10,589
1,296	1,433	1,010	771	794	811	831	852
(2,087)	7,863	9,633	9,350	9,383	9,718	11,148	9,737
(2,086)	142	1,316	1,382	825	102	(127)	(133)
—	—	—	—	—	—	—	—
($ 4,173)	$ 8,005	$ 10,949	$ 10,732	$ 10,208	$ 9,820	$ 11,021	$ 9,604
($ 0.40)	$ 0.03	$ 0.27	$ 0.29	$ 0.18	$ 0.02	($ 0.03)	($ 0.03)
(0.40)	1.54	1.95	1.97	2.05	2.18	2.57	2.48
($ 0.80)	$ 1.57	$ 2.22	$ 2.26	$ 2.23	$ 2.20	$ 2.54	$ 2.45
($ 0.40)	$ 0.03	$ 0.27	$ 0.29	$ 0.18	$ 0.02	($ 0.03)	($ 0.03)
(0.40)	1.54	1.95	1.97	2.05	2.18	2.57	2.48
($ 0.80)	$ 1.57	$ 2.22	$ 2.26	$ 2.23	$ 2.20	$ 2.54	$ 2.45
$ 0.96	$ 1.61	$ 2.12	$ 2.12	$ 2.12	$ 2.11	$ 2.08	$ 2.04
5,243	5,112	4,933	4,747	4,588	4,457	4,345	3,919
5,243	5,112	4,933	4,747	4,588	4,457	4,345	3,919

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • At December 31

Dollars in thousands	2001	2000	1999
Assets			
Utility plant, at original cost	**$302,489**	$291,107	$283,917
Less accumulated depreciation	**119,054**	110,273	102,854
Net utility plant	**183,435**	180,834	181,063
Property under capital lease	**5,959**	6,449	7,038
Construction work in progress	**7,464**	7,389	4,795
Total utility plant, net	**196,858**	194,672	192,896
Associated companies, at equity	**14,093**	14,373	14,545
Other investments	**6,852**	6,357	6,120
Current assets	**36,183**	53,652	33,238
Deferred charges	**75,073**	46,036	43,296
Non-Utility			
Current assets	**8**	8	48
Property and equipment	**250**	252	253
Business segment held for disposal	**—**	—	9,477
Other assets	**817**	1,258	1,321
Total non-utility assets	**1,075**	1,518	11,099
Total assets	**$330,134**	$316,608	$301,194
Capitalization and Liabilities			
Capitalization			
Common stock equity			
Common stock	**$ 19,004**	$ 18,608	$ 18,085
Additional paid-in capital	**74,581**	73,321	72,594
Retained earnings	**8,070**	493	10,344
Treasury stock, at cost	**(378)**	(378)	(378)
Total common stock equity	**101,277**	92,044	100,645
Redeemable cumulative preferred stock	**12,560**	12,795	14,435
Long-term debt, less current maturities	**74,400**	72,100	81,800
Total capitalization	**188,237**	176,939	196,880
Capital lease obligation	**5,959**	6,449	7,038
Current liabilities	**38,841**	68,109	38,150
Accumulated deferred income taxes	**23,759**	25,644	25,201
Unamortized investment tax credits	**3,413**	3,695	3,978
Pine Street Barge Canal site cleanup	**10,059**	11,554	8,815
Deferred credits and other	**58,165**	20,901	21,132
Non-Utility			
Current liabilities	**—**	—	—
Other liabilities	**1,701**	3,317	—
Total non-utility liabilities	**2,539**	3,317	—
Total capitalization and liabilities	**$330,134**	$316,608	$301,194

Consolidated Statements of Retained Earnings

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

Dollars in thousands	2001	2000	1999
Balance at beginning of year	**$ 493**	$10,344	$17,508
Net income (loss)	**11,611**	(5,840)	(3,063)
	12,104	4,504	14,445
Deduct cash dividends declared			
Redeemable cumulative preferred stock	**933**	1,014	1,155
Common stock	**3,101**	2,997	2,946
Total	**4,034**	4,011	4,101
Balance at year end	**$ 8,070**	$ 493	$10,344

1998	1997	1996	1995	1994	1993	1992	1991
$276,853	$265,441	$248,135	$239,291	$227,991	$214,977	$201,643	$194,179
94,604	87,689	81,286	75,797	69,246	64,226	58,516	55,658
182,249	177,752	166,849	163,494	158,745	150,751	143,127	138,521
7,696	8,342	9,006	9,778	10,278	11,029	11,950	12,627
5,611	10,626	13,998	8,727	6,964	9,631	9,646	8,582
195,556	196,720	189,853	181,999	175,987	171,411	164,723	159,730
15,048	15,860	15,769	16,024	16,684	16,886	17,139	17,798
5,630	6,137	4,865	4,224	4,067	5,642	4,561	3,826
35,700	29,125	30,901	30,216	28,798	26,215	28,067	26,778
35,576	35,831	43,224	42,951	35,659	33,893	19,012	11,271
7,974	11,654	4,490	4,131	6,295	3,656	5,016	3,233
1,213	10,784	11,226	11,478	11,329	11,331	10,589	7,971
—	—	—	—	—	—	—	—
18,127	19,622	24,211	22,259	15,792	13,639	8,111	8,628
27,314	42,060	39,927	37,868	33,416	28,626	23,716	19,832
$314,824	$325,733	$324,539	$313,282	$294,611	$282,673	$257,218	$239,235

$ 17,711	$ 17,318	$ 16,790	$ 16,168	$ 15,592	$ 15,120	$ 14,712	$ 14,359
71,914	70,720	68,226	64,206	60,378	57,178	53,510	50,668
17,508	26,717	26,916	26,412	25,727	25,229	24,801	22,806
(378)	(378)	(378)	(378)	(378)	(378)	(378)	(378)
106,755	114,377	111,554	106,408	101,319	97,149	92,645	87,455
16,085	17,735	19,310	8,930	9,135	9,385	9,575	9,825
88,500	93,200	94,900	91,134	74,967	79,800	67,644	56,270
211,340	225,312	225,764	206,472	185,421	186,334	169,864	153,550
7,696	8,342	9,006	9,778	10,278	11,029	11,950	12,627
28,825	25,286	21,037	32,629	40,441	37,925	30,099	32,893
23,389	23,501	26,726	25,292	22,082	21,001	15,504	12,415
4,260	4,542	4,825	5,107	5,390	5,672	5,955	6,240
11,220	—	—	—	—	—	—	—
21,020	25,680	23,417	21,642	21,962	13,541	11,805	11,039
720	1,119	1,752	1,124	918	666	3,524	2,353
6,354	11,951	12,012	11,238	8,119	6,505	8,517	8,118
7,074	13,070	13,764	12,362	9,037	7,171	12,041	10,471
$314,824	$325,733	$324,539	$313,282	$294,611	$282,673	$257,218	$239,235

1998	1997	1996	1995	1994	1993	1992	1991
$26,717	$26,916	$26,412	$25,727	$25,229	$24,801	$22,806	$21,187
(2,878)	9,438	11,959	11,503	11,002	10,631	11,852	10,456
23,839	36,354	38,371	37,230	36,231	35,432	34,658	31,643
1,296	1,433	1,010	771	794	811	831	852
5,035	8,204	10,445	10,047	9,710	9,392	9,026	7,985
6,331	9,637	11,455	10,818	10,504	10,203	9,857	8,837
$17,508	$26,717	$26,916	$26,412	$25,727	$25,229	$24,801	$22,806

Consolidated Statements of Cash Flows

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2001	2000	1999
		(In thousands)	
Operating Activities:			
Net Income (Loss)	**$ 11,611**	($ 5,840)	($3,063)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**14,294**	15,304	16,187
Dividends from associated companies less equity income	**280**	(26)	169
Allowance for funds used during construction	**(398)**	(512)	(224)
Amortization of purchased power costs	**3,767**	5,575	5,725
Deferred income taxes	**(2,167)**	161	1,530
Provision for loss on disposal of business segment	**182**	6,549	6,676
Accrued purchase power option call	**(8,276)**	8,276	—
Deferred purchased power costs	**1,126**	(6,692)	(6,590)
Rate levelization liability	**8,527**	—	—
Provision for chargeoff of deferred regulatory asset	**—**	3,229	—
Environmental proceedings and conservation expenditures	**(3,380)**	(2,073)	(8,048)
Changes in current assets and current liabilities	**8,098**	(9,628)	4,751
Other	**1,626**	(3,364)	(2,008)
Net cash provided by operating activities	**35,290**	10,959	15,105
Net cash provided (used) by discontinued segment	**(1,797)**	245	(138)
Net cash provided by operating activities	**33,493**	11,204	14,967
Investing Activities:			
Construction expenditures	**(12,963)**	(13,853)	(9,174)
Investment in non-utility property	**(212)**	(187)	(190)
Proceeds from sale of subsidiaries	**—**	6,000	—
Investment in associated companies	**—**	—	—
Special fund for postretirement benefits	**—**	—	—
Net cash used in investing activities	**(13,175)**	(8,040)	(9,364)
Financing Activities:			
Investment in certificate pledged	**16,173**	(15,437)	—
Issuance of preferred stock	**—**	—	—
Reduction in preferred stock	**(235)**	(1,640)	(1,650)
Power supply option obligation	**(16,012)**	15,419	—
Issuance of common stock	**1,655**	1,250	1,054
Short-term debt, net	**(15,500)**	7,600	900
Issuance of long-term debt	**12,000**	—	—
Reduction in long-term debt	**(9,700)**	(6,700)	(1,700)
Cash dividends	**(4,034)**	(4,011)	(4,101)
Net cash provided by (used in) financing activities	**(15,653)**	(3,519)	(5,497)
Net increase (decrease) in cash and cash equivalents	**4,665**	(355)	106
Cash and cash equivalents at beginning of year	**341**	696	590
Cash and Cash Equivalents at End of Year	**$ 5,006**	$ 341	$ 696

	1998	1997	1996	1995	1994	1993	1992	1991
	($ 2,878)	$ 9,438	$ 11,959	$ 11,503	$ 11,002	$ 10,631	$ 11,852	$ 10,456
	16,059	16,359	16,280	14,116	10,683	8,572	8,065	7,046
	812	(90)	254	660	202	254	659	190
	(235)	(672)	(643)	(574)	(803)	(630)	(388)	(356)
	6,405	5,212	5,187	6,036	4,178	3,723	3,825	1,840
	(394)	(2,997)	1,655	3,432	1,302	4,897	2,805	1,244
	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—
	(7,830)	(331)	(5,917)	(12,935)	(536)	(6,432)	(5,347)	104
	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—
	1,177	(4,534)	(4,927)	(5,311)	715	(10,608)	(5,618)	(2,374)
	(3,822)	(2,517)	781	(595)	(4,220)	1,221	(577)	(1,385)
	645	6,230	1,738	(95)	2,383	(1,936)	44	4,380
	9,939	26,098	26,367	16,237	24,906	9,692	15,320	21,145
	—	—	—	—	—	—	—	—
	9,939	26,098	26,367	16,237	24,906	9,692	15,320	21,145
	(10,900)	(16,409)	(17,541)	(15,314)	(13,536)	(15,949)	(15,327)	(19,475)
	(1,442)	218	(2,203)	(6,121)	(1,220)	(5,950)	(282)	(2,305)
	11,500	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—
	—	—	—	—	—	(601)	(56)	(1,463)
	(842)	(16,191)	(19,744)	(21,435)	(14,756)	(22,500)	(15,665)	(23,243)
	—	—	—	—	—	—	—	—
	—	—	12,000	—	—	—	—	—
	(1,650)	(1,575)	(1,620)	(205)	(250)	(190)	(250)	(262)
	—	—	—	—	—	—	—	(96)
	1,587	3,428	4,642	4,404	3,671	4,077	3,195	13,893
	4,384	1,600	(7,400)	(11,799)	1,198	7,402	(2,093)	2,302
	—	—	14,000	25,917	—	20,000	17,000	—
	(6,767)	(4,201)	(16,201)	(4,833)	(1,800)	(8,530)	(7,246)	(5,116)
	(6,332)	(9,637)	(11,455)	(10,818)	(10,504)	(10,204)	(9,857)	(8,837)
	(8,778)	(10,385)	(6,034)	2,666	(7,685)	12,555	749	1,980
	319	(478)	589	(2,532)	2,465	(253)	404	(118)
	271	749	160	2,692	227	480	76	194
	$ 590	$ 271	$ 749	$ 160	$ 2,692	$ 227	$ 480	$ 76

Common Stock Data and Stock Ratios

GREEN MOUNTAIN POWER CORPORATION • At and for the Years Ended December 31

		2001	2000	1999
Common Stock Data				
Net income (loss) applicable to common stock (in thousands)	($)	**10,678**	(6,854)	(4,218)
Shares outstanding (in thousands and net of treasury shares)				
Year-end		**5,685**	5,567	5,410
Weighted average		**5,630**	5,491	5,361
Per share of common stock				
Earnings (loss) per average share (Note 1)	($)	**1.90**	(1.25)	(0.79)
Dividends paid	($)	**0.55**	0.55	0.55
Payout ratio (Note 5)	(%)	**29.0**	—	—
Net book value	($)	**17.81**	16.53	18.60
Price range N.Y.S.E.				
High	($)	**19.50**	12-13/16	14
Low	($)	**11.06**	6-7/8	7-1/8
Year-end	($)	**18.65**	12-1/2	7-7/16
Price Earnings Ratio (price at year-end) (Note 5)		**10**	—	—
Capitalization (in thousands)				
Common stock equity	($)	**101,277**	92,044	100,645
Redeemable cumulative preferred stock	($)	**12,560**	12,795	14,435
Long-term debt (including current maturities)	($)	**84,100**	81,800	88,500
Total	($)	**197,937**	186,639	203,580
Capitalization Ratios				
Common stock equity	(%)	**51.2**	49.3	49.4
Redeemable cumulative preferred stock	(%)	**6.3**	6.9	7.1
Long-term debt (including current maturities)	(%)	**42.5**	43.8	43.5
Total	(%)	**100.0**	100.0	100.0
Other Financial Ratios				
Long-term debt weighted average annual interest rate	(%)	**7.1**	7.5	7.5
Preferred stock weighted average annual dividend rate	(%)	**7.3**	7.5	7.5
Income before interest and income taxes to long-term debt interest		**4.2**	0.1	0.8
Income before interest and after income taxes to long-term debt interest		**3.1**	0.2	0.6
Income before interest and after income taxes to total interest charges and preferred dividends		**2.3**	0.2	0.5
Operating revenues as a % of net utility property (year-end) (Note 2)	(%)	**134.4**	132.7	115.2
Operating expenses (excluding income taxes) as a % of operating revenues	(%)	**91.7**	98.4	96.3
Annual depreciation expense as a % of depreciable property	(%)	**3.5**	3.5	3.3
Accumulated depreciation as a % of depreciable property	(%)	**39.4**	37.9	36.2
Return on average common equity (Note 3)	(%)	**11.0**	(7.1)	(4.0)
Internally generated funds as a % of capital requirements, sinking fund obligations and other requirements (Note 4)	(%)	**82.0**	59.4	89.0
AFUDC as a % of net income (loss) applicable to common stock	(%)	**3.7**	(7.5)	(5.3)

NOTES:
(1) Based on weighted average number of shares outstanding during each year, excluding number of shares held in treasury.
(2) Includes investment in associated companies.
(3) Average common equity is computed using a thirteen-month average.
(4) Internally generated funds are net of dividend payments.
(5) Measure is not meaningful for years with net loss.

1998	1997	1996	1995	1994	1993	1992	1991
(4,173)	8,005	10,949	10,732	10,208	9,820	11,021	9,604
5,297	5,180	5,021	4,835	4,662	4,520	4,398	4,292
5,243	5,112	4,933	4,747	4,588	4,457	4,345	3,919
(0.80)	1.57	2.22	2.26	2.23	2.20	2.54	2.45
0.9625	1.61	2.12	2.12	2.12	2.11	2.08	2.04
—	102.5	95.5	93.8	95.1	95.9	81.9	83.3
20.15	22.08	22.22	22.01	21.73	21.49	21.07	20.38
20-1/16	26-1/4	29-1/8	28-5/8	31-1/4	36-5/8	33-5/8	30-1/4
10-1/16	17-5/8	22-3/4	23-7/8	23-3/8	30-3/4	29	22
10-1/2	18-3/8	23-7/8	27-3/4	27-7/8	31	33-1/8	29-7/8
—	12	11	12	13	14	13	12
106,755	114,377	111,554	106,408	101,319	97,149	92,645	87,455
16,085	17,735	19,310	8,930	9,135	9,385	9,575	9,825
90,200	94,900	97,934	98,967	79,800	81,600	70,130	60,376
213,040	227,012	228,798	214,305	190,254	188,134	172,350	157,656
50.1	50.4	48.8	49.7	53.3	51.6	53.7	55.5
7.6	7.8	8.4	4.2	4.8	5.0	5.6	6.2
42.3	41.8	42.8	46.1	41.9	43.4	40.7	38.3
100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
7.6	7.7	8.1	9.0	8.7	9.4	9.8	10.2
7.5	7.6	8.8	8.5	8.5	8.5	8.5	8.5
0.5	3.3	3.8	3.7	3.4	3.6	3.9	3.9
0.7	2.3	2.8	2.9	2.6	2.7	2.9	2.9
0.5	1.9	2.3	2.3	2.3	2.3	2.4	2.2
80.7	75.1	78.9	73.4	69.5	71.4	75.4	77.1
97.8	87.3	87.4	87.1	86.6	85.7	83.9	85.7
3.4	3.2	3.3	3.3	3.2	3.2	3.2	3.2
36.2	34.9	34.5	33.8	32.4	31.8	30.8	32.0
(3.8)	7.1	10.0	10.3	10.3	10.3	12.2	12.5
64.6	129.4	38.8	58.0	83.7	46.2	50.3	40.9
(5.6)	8.4	5.9	5.3	7.9	6.4	3.5	3.7

Employees, Plant Investment, Sales of Securities

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

Dollars in thousands	2001	2000	1999
Number of Active Employees full and part time, at December 31,			
—Green Mountain Power	**193**	197	196
—Subsidiaries	**0**	5	5
Utility Plant Investment (year-end)			
Intangible	**$ 14,214**	$ 11,726	$ 11,276
Steam production	**10,609**	10,525	10,460
Hydro production	**30,581**	29,728	29,667
Other production	**21,924**	21,833	22,141
Transmission	**35,734**	35,100	34,793
Distribution	**163,930**	157,959	151,873
General	**25,496**	24,236	23,707
Total utility plant investment	**302,488**	291,107	283,917
Less accumulated depreciation	**119,053**	110,273	102,854
Net utility plant	**183,435**	180,834	181,063
Property under capital lease	**5,959**	6,449	7,038
Construction work in progress	**7,464**	7,389	4,794
Total utility plant investment, net	**$196,858**	$194,672	$192,895
Beginning balance—utility plant	**$291,107**	$283,917	$276,853
Transfers to utility plant from CWIP	**13,927**	11,258	9,990
Retirements from utility plant	**(2,546)**	(4,068)	(2,926)
Ending balance—utility plant	**$302,488**	$291,107	$283,917
Beginning balance—construction work in progress	**$ 7,389**	$ 4,794	$ 5,611
Construction expenditures, net of customer advances	**14,002**	13,853	9,173
Transfers to utility plant	**(13,927)**	(11,258)	(9,990)
Ending balance—construction work in progress	**$ 7,464**	$ 7,389	$ 4,794
Sales of Securities (gross proceeds)			
Long-term debt	**$ 12,000**	$ —	$ —
Common stock (excludes DRIP, ESIP, PAYSOP, restricted shares and stock grants)	**—**	—	—
Redeemable cumulative preferred stock	**—**	—	—
Total sales of securities	**$ 12,000**	$ —	$ —

1998	1997	1996	1995	1994	1993	1992	1991
288	321	344	350	373	387	388	392
6	48	45	50	59	58	82	73
$ 10,206	$ 9,168	$ 6,330	$ 7,451	$ 6,415	$ 4,571	$ 3,126	$ 4,582
10,782	10,702	10,702	10,799	10,752	10,748	10,688	10,679
29,435	29,200	28,771	26,315	25,757	24,930	24,034	23,820
22,217	22,862	18,239	18,393	18,427	18,402	17,533	17,482
34,924	33,878	30,356	29,837	29,344	28,698	25,623	25,335
145,694	136,825	131,626	124,330	116,325	107,489	101,367	94,142
23,595	22,806	22,111	22,166	20,971	20,139	19,272	18,139
276,853	265,441	248,135	239,291	227,991	214,977	201,643	194,179
94,604	87,689	81,286	75,797	69,246	64,226	58,516	55,658
182,249	177,752	166,849	163,494	158,745	150,751	143,127	138,521
7,696	8,342	9,006	9,778	10,278	11,029	11,950	12,627
5,611	10,626	13,998	8,727	6,964	9,631	9,646	8,582
$195,556	$196,720	$189,853	$181,999	$175,987	$171,411	$164,723	$159,730
$265,441	$248,135	$239,291	$227,991	$214,977	$201,643	$194,179	$182,293
15,927	20,222	12,522	13,403	16,204	15,223	11,644	16,839
(4,515)	(2,916)	(3,678)	(2,103)	(3,190)	(1,889)	(4,180)	(4,953)
$276,853	$265,441	$248,135	$239,291	$227,991	$214,977	$201,643	$194,179
$ 10,626	$ 13,998	$ 8,727	$ 6,964	$ 9,631	$ 9,646	$ 8,582	$ 8,634
10,912	16,850	17,793	15,166	13,537	15,208	12,708	16,787
(15,927)	(20,222)	(12,522)	(13,403)	(16,204)	(15,223)	(11,644)	(16,839)
$ 5,611	$ 10,626	$ 13,998	$ 8,727	$ 6,964	$ 9,631	$ 9,646	$ 8,582
$ —	$ —	$ 14,000	$ 24,000	$ —	$ 20,000	$ 17,000	$ —
—	—	—	—	—	—	—	12,136
—	—	12,000	—	—	—	—	—
$ —	$ —	$ 26,000	$ 24,000	$ —	$ 20,000	$ 17,000	$ 12,136

Power Supply Statistics, Electric Sales

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2001	2000	1999
Net System Capability During Peak Month (MW*)			
Total capability (MW)	**408.0**	411.1	393.2
Net system peak	**341.2**	323.5	317.9
Reserve (MW)	**66.8**	87.6	75.3
Reserve % of peak	**19.6%**	27.1%	23.7%
Net Production (MWH)**			
Hydro	**951,146**	1,053,223	1,095,738
Lease transmissions	**—**	—	—
Nuclear	**736,420**	803,303	731,431
Conventional steam	**2,670,249**	2,704,427	2,328,267
Internal combustion	**18,291**	35,699	12,312
Combined cycle	**72,653**	73,433	99,962
Wind	**12,135**	12,246	7,956
Total production	**4,460,894**	4,682,331	4,275,666
Less nonrequirements sales to other utilities	**2,365,809**	2,573,576	2,152,781
Production for requirements sales	**2,095,085**	2,108,755	2,122,885
Less requirements sales and lease transmissions (MWH)	**1,956,232**	1,954,898	1,920,257
Losses and Company use (MWH)	**138,853**	153,857	202,628
Losses as a % of total production	**3.11%**	3.29%	4.74%
System load factor (***)	**70.1%**	74.2%	76.2%
Sales and Lease Transmissions (MWH)**			
Residential—GMP	**549,151**	558,682	544,447
Lease MWH transmitted	**—**	—	—
Total Residential	**549,151**	558,682	544,447
Commercial & industrial–small	**718,969**	704,126	688,493
Commercial & industrial–large	**683,004**	683,296	664,110
Other	**2,030**	6,713	3,138
Total retail sales and lease transmissions	**1,953,154**	1,952,817	1,900,188
Sales to Municipals & Cooperatives (Rate W)	**3,078**	2,081	20,069
Total Requirements Sales	**1,956,232**	1,954,898	1,920,257
Other Sales for Resale	**2,365,809**	2,573,576	2,152,781
Total sales and lease transmissions	**4,322,041**	4,528,474	4,073,038
Average Number of Electric Customers			
Residential	**73,249**	72,424	71,515
Commercial & industrial–small	**12,984**	12,746	12,438
Commercial & industrial–large	**22**	23	23
Other	**65**	65	66
Total	**86,320**	85,258	84,042
Average Revenue Per KWH (Cents)			
Residential including lease revenues	**13.33**	12.50	12.32
Lease charges	**—**	—	—
Total Residential	**13.33**	12.50	12.32
Commercial & industrial–small	**10.83**	10.00	9.88
Commercial & industrial–large	**7.69**	6.51	6.55
Total retail including lease revenues	**10.44**	9.52	9.47
Average Use and Revenue Per Residential Customer			
KWH including lease transmissions	**7,497**	7,717	7,617
Revenues including lease revenues	**$999**	$965	$938

*MW—Megawatt is one thousand kilowatts. **MWH—Megawatthour is one thousand kilowatthours.

1998	1997	1996	1995	1994	1993	1992	1991
396.9	416.9	425.8	396.1	438.2	474.7	439.9	415.1
312.5	311.5	313.0	297.1	308.3	307.3	314.4	308.5
84.4	105.4	112.8	99.0	129.9	167.4	125.5	106.6
27.0%	33.8%	36.0%	33.3%	42.1%	54.5%	39.9%	34.6%
972,723	1,073,246	1,192,881	1,043,617	742,088	751,078	641,525	611,658
—	—	—	—	—	15,425	58,374	67,600
607,708	772,030	680,613	682,814	763,690	598,245	665,034	731,582
750,602	560,504	705,331	673,982	651,105	748,626	762,451	799,781
40,148	4,827	2,674	6,646	3,532	2,849	1,504	3,809
118,322	104,836	51,162	92,723	37,808	40,966	60,138	104,344
—	—	—	—	—	—	—	—
2,489,503	2,515,443	2,632,661	2,499,782	2,198,223	2,157,189	2,189,026	2,318,774
499,409	524,192	663,175	582,942	328,794	271,224	273,087	448,110
1,990,094	1,991,251	1,969,486	1,916,840	1,869,429	1,885,965	1,915,939	1,870,664
1,883,959	1,870,913	1,814,371	1,760,830	1,730,497	1,749,454	1,794,986	1,742,308
106,134	120,338	155,115	156,010	138,932	136,511	120,953	128,356
4.26%	4.78%	5.89%	6.24%	6.32%	6.33%	5.53%	5.54%
72.7%	73.0%	71.6%	73.7%	69.2%	70.1%	68.5%	67.9%
533,904	549,259	557,726	549,296	564,635	541,579	505,234	483,998
—	—	—	—	—	15,425	58,374	67,600
533,904	549,259	557,726	549,296	564,635	557,004	563,608	551,598
665,707	645,331	630,839	608,688	604,686	593,560	582,594	571,818
636,436	608,051	584,249	556,278	521,400	529,372	539,665	519,201
3,476	3,939	2,898	8,855	1,146	8,868	6,312	2,770
1,839,522	1,806,580	1,775,712	1,723,117	1,691,867	1,688,804	1,692,179	1,645,387
44,437	64,333	38,659	37,713	38,630	60,650	102,807	96,921
1,883,959	1,870,913	1,814,371	1,760,830	1,730,497	1,749,454	1,794,986	1,742,308
499,409	524,192	663,175	582,942	328,794	271,224	273,087	448,110
2,383,368	2,395,105	2,477,546	2,343,772	2,059,291	2,020,678	2,068,073	2,190,418
71,301	70,671	70,198	69,659	68,811	67,994	67,201	66,406
12,170	11,989	11,828	11,712	11,611	11,447	11,245	11,215
23	23	25	24	24	25	24	24
70	75	75	76	76	74	73	71
83,564	82,758	82,126	81,471	80,522	79,540	78,543	77,716
11.56	11.18	10.87	10.09	9.03	8.94	8.44	8.06
—	—	—	—	—	.06	.41	.26
11.56	11.18	10.87	10.09	9.03	9.00	8.85	8.32
9.29	9.10	8.96	8.42	8.00	7.97	7.82	7.53
6.32	6.22	6.28	5.86	6.02	5.96	5.89	5.72
8.96	8.79	8.72	8.36	7.96	7.86	7.56	7.29
7,488	7,772	7,945	7,885	8,206	8,192	8,387	8,306
$865	$869	$863	$796	$741	$733	$707	$670

***Load factor is based on net system peak and firm MWH production less off-system losses.

Shareholder Information

CONTACTS:

	Green Mountain Power Corporation 163 Acorn Lane Colchester, VT 05446 (802)864-5731
Corporate Secretary:	Penny J. Collins (802)655-8410 e-mail: collins@greenmountainpower.biz
Investor Relations:	Stephen C. Terry Senior Vice President, Corporate and Legal Affairs (802)655-8408 terry@greenmountainpower.biz
News Media Inquiries:	Dorothy A. Schnure Manager, Corporate Communications (802)655-8418 schnure@greenmountainpower.biz
Internet:	www.greenmountainpower.biz

SHAREHOLDER SERVICES:

Transfer Agent and Registrar:	ChaseMellon Shareholder Services, L.L.C. e-mail: www.chasemellon.com (800)851-9677

Shareholder services involving stock transfers, lost certificates, dividend problems, address changes or dividend reinvestment: ChaseMellon Shareholder Services, L.L.C.
Overpeck Centre
85 Challenger Road
Ridgefield Park, NJ 07660
(800)851-9677

Annual Report on Form 10-K
A copy of the 2001 Annual Report on Form 10-K filed with the Securities and Exchange Commission is available upon request to the Corporate Secretary.

Common Stock Listing:
New York Stock Exchange
Symbol: GMP

Dividend Schedule for 2002 (approximate)

Record Dates	Payment Dates
Mid-March	March 29
Mid-June	June 28
Mid-September	September 30
Mid-December	December 31

Bond Ratings as of December 31, 2001 (See page 16 for details)

	Fitch	Moody's	S&P
First Mortgage Bonds	BBB	Baa2	BBB
Preferred Stock	BBB-	ba2	BB

Dividend Reinvestment and Stock Purchase Plan

GMP offers a Dividend Reinvestment and Stock Purchase Plan that provides a low-cost way for shareholders of record and Vermont residents to purchase additional shares of common stock directly from the Company through optional investments and reinvested dividends. The price of common stock purchased with reinvested dividends will be at a 5% discount. Participants in the Plan may make optional cash investments of $50 per investment, not to exceed $40,000 per year. The transfer agent must receive the investment at least five business days prior to month-end, since optional cash investments are made the last business day of each month. The plan also offers safekeeping of certificate shares. Prospectuses and authorization forms may be obtained from the Company or the transfer agent.

Transferring Stock

A stock transfer is required whenever there is a change in the name or names in which the stock certificate is registered. This can happen when you sell the stock, make a gift of stock, or add or delete owners of the certificate. To transfer your stock, fill in the name, address and taxpayer identification number on the back of your certificate and sign your name exactly as it appears on the front. Your signature must be guaranteed by a commercial bank, or a brokerage firm that is a member of a major stock exchange. Your certificate, fully endorsed, should be sent to the transfer agent by registered or certified mail.

Replacement of Dividend Checks

If you do not receive your dividend check within 10 business days after the dividend payment date, or if your check becomes lost or destroyed, you should notify the transfer agent so payment may be stopped and a replacement check issued.

Lost or Stolen Certificates

Stock certificates are valuable pieces of paper that should be kept in a safe place. If your stock certificate is lost, destroyed or stolen, please notify the transfer agent immediately so that a "stop transfer" can be placed on the missing certificate. The transfer agent will send you the necessary documents to obtain a replacement certificate. There is a charge for certificate replacements.

Duplicate Mailings and Multiple Dividend Checks

Some shareholders maintain several accounts with slight variation in the registered ownership (John A. Smith, J.A. Smith, or John A. Smith and Mary K. Smith). Even though the mailing address is identical, we are required by law to create a separate account for each name and to mail separate dividend checks, annual reports and proxy material to each account.

If you want to maintain separate accounts but eliminate duplicate mailings of annual reports, simply write to the transfer agent and list the account(s) for which mailings should continue or be discontinued. Dividend checks and proxy materials will still be sent to each account.

If you would like to consolidate your accounts, write to the transfer agent stating which account you want to remain open and which ones you want consolidated. It may be necessary to reissue stock certificates.

2002 Annual Shareholders Meeting

All shareholders are invited to attend GMP's Annual Meeting on Thursday, May 16, 2002 at the Sheraton Hotel and Conference Center, 870 Williston Road, South Burlington, Vermont. The meeting will begin at 10 a.m.