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The Path

Green Mountain Power Corporation • Annual Report to Shareholders 2002

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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.

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Financial and Operating Highlights

	2002	2001	2000
Financial Data			
Operating revenues	**$274,608,000**	$283,464,000	$277,326,000
Operating expenses	**$259,528,000**	$267,005,000	$272,066,000
Net income (loss), continuing operations	**$ 11,299,000**	$ 10,860,000	($ 305,000)
Net income (loss), discontinued operations	**99,000**	($ 182,000)	($ 6,549,000)
Net income (loss) applicable to common stock	**$ 11,398,000**	$ 10,678,000	($ 6,854,000)
Total utility plant	**$311,543,000**	$309,953,000	$298,496,000
Common Share Data			
Weighted average shares outstanding	**5,592,000**	5,630,000	5,491,000
Year-end shares outstanding	**4,955,000**	5,685,000	5,567,000
Diluted earnings (loss) per average share, continuing operations	**$ 1.96**	$ 1.88	($ 0.06)
Diluted earnings (loss) per average share, discontinued operations	**$ 0.02**	($ 0.03)	($ 1.19)
Diluted earnings (loss) per average share	**$ 1.98**	$ 1.85	($ 1.25)
Dividends paid per share	**$ 0.60**	$ 0.55	$ 0.55
Year-end book value per share	**$18.51**	$17.81	$16.53
Dividend yield on ending market value	**2.87%**	2.95%	4.40%
Return on average common equity	**11.03%**	11.02%	–7.10%
Operating Data			
Electric customers—year-end	**88,000**	87,000	86,000
Retail and requirements sales (MWH)	**1,952,000**	1,956,000	1,955,000
Other sales for resale (MWH)	**2,104,000**	2,365,000	2,574,000
Average revenue per kWh (cents)	**10.09**	10.44	9.52
Number of Employees—Year-End			
Green Mountain Power	**194**	193	197
Subsidiaries	**0**	0	5

They took one look at the job and the twelve members of this Green Mountain Power taskforce knew, just knew, they couldn't do it, not in time. But none of them said so. They shrugged off their packs, took out the axes, shovels, and picks and went to work. The sweat poured, the insects swarmed, and the brush fell. Slowly but surely the forest gave ground, the gnarly roots were extracted, the brush was removed and a new path took shape. Several hours later this spur of the Long Trail, one of Vermont's most prized natural resource jewels, was mended and again ready for use by the scores of hikers who pass this point on their way from Massachusetts to Canada.

The Green Mountain Power crew had been invited last September for the volunteer assignment by the club that serves as custodian for Vermont's famed Long Trail. This spot, high in the mountains and miles from the nearest electrical service — and thus far from the crew's usual workstations — was a particularly hard-used area of the trail. And as a result it had, in the most basic way, collapsed. The trail had eroded until it was not only unwise but downright dangerous to use it. For some of the crew, it had been a long time since they had calloused their hands on axes and shovels. Before the day was over more than one of them wondered, but not aloud, why they had chosen to spend a perfectly fine September day trying to tame a wilderness.

In the end, as they packed up and made one final tidying up patrol over their new trail, more than one crew member turned to one of their colleagues, CEO Chris Dutton, and said, "Thanks for letting us do this." Before leaving, they took one last look at the old, worn path with its dangerous overhang, now buried beneath brush and rocks, and they were thrilled to think that even though few would even know the bad spot had existed, no hiker would have to wonder if this new trail was passable.

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Dear Green Mountain Power Shareholder:

One of the truly satisfying feelings in life comes at that moment when you finish a difficult job, say a rescue, that had totally absorbed all your energies right up to the final effort at the very last hour. Such a moment is particularly savory if the task not only is worthy in its own right, but also helps preserve a valuable treasure. A team of Green Mountain Power employees had that experience on the Long Trail last fall.

And this little one-day episode also describes pretty well the way Green Mountain Power's 194 employees feel about our journey over the past five years. Our corporate trail has been rebuilt and the path ahead, while not perfectly clear, is passable. And we're working together in new ways we wouldn't have thought possible just a few years ago.

Green Mountain Power's performance in 2002 was strong, with a return on common equity for core operations of 11.25 percent, the target established by the Vermont Public Service Board to be a fair return for our shareholders. Earnings for the year were $1.98, above the $1.85 we earned in 2001. Despite the slumping economy and a warmer than normal winter, we met our financial operating targets.

Green Mountain Power's performance stood in stark contrast to the record of the electric utility industry, which in 2002 saw regulatory and public confidence severely challenged. Instead of retreating into a defensive crouch, we had the confidence to change the Company's financial structure, to mitigate power supply risks, to expand business development, and to continue to improve customer performance with a streamlined operation. The support of the investment community, including our shareholders, was critical to our ability to re-establish and improve our financial strength.

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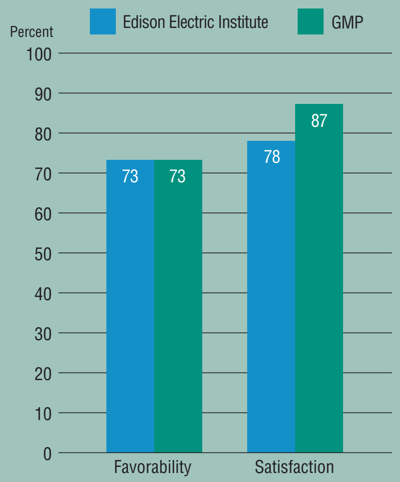
Green Mountain Power's bond ratings were among the few upgraded by Moody's Investor Service and by Fitch in 2002; two-thirds of the electric utility industry received downgrades. Higher bond ratings reduce the Company's cost of capital and provide tangible evidence of our improving financial strength, so the upgrades were an important affirmation. We significantly altered our financial structure in 2002. In the fall, we successfully bought back 811,783 shares of common stock at a price attractive not only to selling shareholders, but also to you, our remaining owners. We also issued $42 million of first mortgage bonds, which replaced substantially all of the Company's short-term and intermediate term debt. These actions reduced the amount of more expensive equity in our capitalization and replaced it with lower cost debt. The Company's capital structure is now closer to the 50-50 balance of debt and equity that we believe is appropriate for financial health in our industry. The buy-back of our stock is the ultimate statement of our confidence that we can continue to build on our strengths and thereby make Green Mountain Power stock a sound utility investment for our shareholders.

In 2002, Green Mountain Power stock price increased 12.4 percent, to close the year at $20.97. When added to the $0.60 cent dividend that Green Mountain Power paid out during 2002, the total return was 15.7 percent.

Our success in restructuring the Company's finances and our financial forecast led your Board of Directors to approve an increase in the dividend payment to an indicated annual rate of $0.76, the first increase in ten years. The Company believes that, in light of the general practice in the utility industry, we should pay out 50 percent to 60 percent of anticipated earnings in dividends. Over the course of the next several years, we intend to increase our dividend in a measured, consistent manner to this payout range, which we will sustain so long as our financial health seems assured.

Customer Favorability and Satisfaction*



Surveys conducted fall 2002.

** 5–7 on a 7-point scale*

for the famed trail. This spot, high in the mountains and miles from the nearest electrical service, was a particularly hard-used area of the trail. As a result it had

Probably the most complex regulatory proceeding in recent years ended positively with the sale of the Vermont Yankee nuclear plant to Entergy in July. Utilities in Vermont, which owned 55 percent of Yankee, pursued the sale to minimize operating and decommissioning risks to customers and shareholders. We expect the sale and the associated power supply purchase contract with Entergy to save Green Mountain Power customers $68 million between now and 2012. The savings flowing from the sale of the plant are a critical component of our desire to maintain our current rate stability. Our rates are currently below the average in New England, and we hope that our rates will remain unchanged for some time.

Power supply cost volatility presents a challenge to a small utility like Green Mountain Power, and we have taken steps, in addition to the sale of Vermont Yankee, to reduce the risks inherent in the wholesale electricity market. In 2002, we extended our agreement with Morgan Stanley, which, when added to our long-term power supply contracts with Hydro Québec and Entergy, means that the bulk of our power supply is "hedged" against extreme market conditions and the volatility of energy prices. The sources we use to supply our customers with power reflect important Vermont values. Last year, about 45 percent of our power came from renewable resources, and our emissions profile is unusually low.

In 2002, Vermont elected Jim Douglas to serve as governor, the first Republican administration since 1991. We are pleased that Vermont's new governor is supportive of appropriate state infrastructure investments that are required to fuel a modern economy. With the new governor comes a change in the leadership of many of the state agencies that we work with, including the Department of Public Service, the Agency of Natural Resources, and the Agency of Commerce. It appears that the new agency heads are creative, enthusiastic and willing to work with us to develop solutions to make Vermont's business climate as competitive as possible in order to encourage economic growth.

Power Supply Costs by Source

Source	2002 Cents per kWh
Average all sources	5.8
GMP hydro	3.1
Nuclear	4.5
Market purchases	4.8
Oil and gas	6.1
Hydro-Québec	6.6
Wind	7.0
Qualifying facilities	11.6

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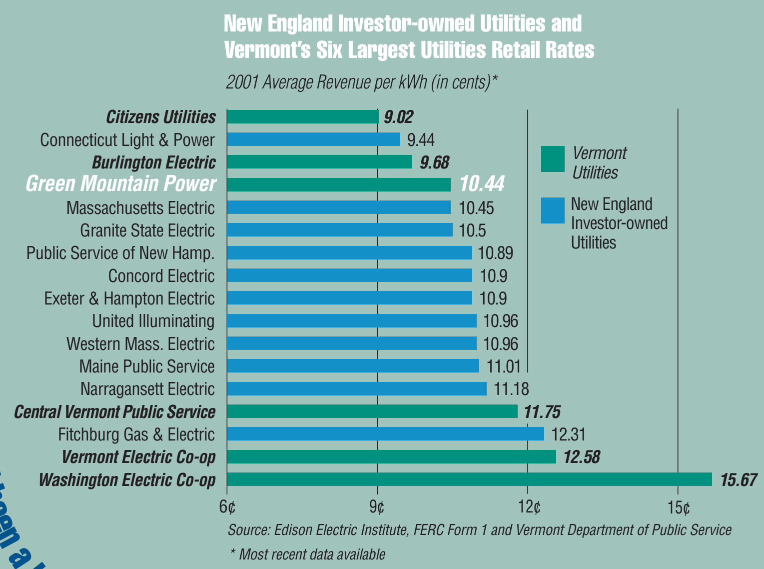


This commitment to Vermont's prosperity is an important message for our Company. Our sole business is to provide electricity and associated services. We do not have and are not interested in acquiring investments in unregulated markets. We are an integrated electric utility whose purpose is very clear and direct: We intend to be the best utility in the United States, balancing high levels of efficiency with premier customer satisfaction. We want to expand our business, and are always searching for the right opportunity to bring more value to our shareholders and electric consumers.

We can apply the skills we use every day in our core business to bring additional revenue into the Company. Through a competitive bid process, Green Mountain Power was awarded a contract to design and build a substation for a municipal utility in Vermont. With 22 mostly small utilities serving Vermont, the majority of them municipally owned, we have begun marketing our utility services to other utilities across the state, and in the Northeast region. This work for other utilities has received support from our Vermont regulators.

Our strong community relations were evident in November, when the Lake Champlain Chamber of Commerce named Green Mountain Power "Business of the Year," citing our "commitment to employees, customers, the community and the environment, all of which benefit from the best-practices GMP adopted as part of its recent corporate restructuring." We were honored to be recognized by this very prominent Vermont business organization, and we are energized to work even harder to improve on our successes.

Last year we reported to you on the new service quality standards and guarantees we developed with State regulators. In 2002, we met or exceeded all the customer service standards, which include performance measures such as how quickly we answer the phone and whether we complete jobs on time. We met seven of the eight reliability criteria by which we measure service interruptions, missing the goal for only one standard and missing that by less than ten percent. In addition, we raised the bar by tightening our money-back service guarantees as a way to show our customers that we are committed to continuing to improve customer service, safety and reliability. For example, now we pay our customers $10 if we do not install new or temporary service within five business days, rather than the previous standard of ten days. Customers appreciate this high level of performance. In an independent survey of our customers, 87 percent were satisfied with Green Mountain Power's service, compared to 78 percent who were satisfied with their electric utility's performance in a national survey.

Vermonters are famously committed to protecting environmental resources. We responded to our customers' interests by pursuing an arrangement with a non-profit organization that gives customers a simple, convenient way to help fight global climate change. Our customers can now choose to include on their Green Mountain Power bill a six-dollar, tax-deductible donation each month to Clean Air-Cool Planet, a non-profit organization that is dedicated to finding and promoting solutions to climate change. The six-dollar donation each month for a year will keep six tons of CO_2 out of the air, which is the amount a typical residential home in Vermont produces in a year. Michael Dworkin, Chairman of the Vermont Public Service Board, commented, "This kind of market-based initiative will give thousands of Vermonters a chance to make a contribution towards a better world for all of us. At the same time, it shows how a small utility can be a leader in an emerging field. I look forward to this innovation becoming a model, as others offer similar choices to their customers." Although the program is in its infancy, customers are responding positively.

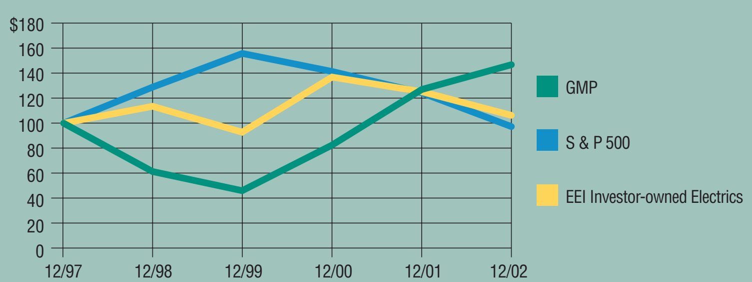
Certainly one way to satisfy customers is to invest in the resources necessary to respond to any interruptions on our system. Our lineworkers have used laptop computers in their trucks for over a year now, giving them access to extremely accurate maps, actual pictures of poles and transformers and spreadsheets of technical information about every piece of equipment on our system. They are able to work faster and more efficiently with this information readily available. In 2002, we expanded the capabilities of our information system. Green Mountain Power linetrucks now have satellite transmitters installed to provide real time information about where the truck is located. Our schedulers can refer to an electronic map of Vermont that shows not only exactly where each truck is at any given moment, but visually represents customer outages. In a large storm, this information is especially valuable in helping us efficiently dispatch our resources to the areas most in need. Our focus on technology never stops returning benefits. Our innovative way of applying existing technology has been so successful that two of the world's largest technology companies, Oracle and Hewlett-Packard, used Green Mountain Power's experience for worldwide promotional purposes.

Technology is one of the tools we've used to make us more efficient. We have remained one of the most efficient electric utilities in the country, as measured by the number of customers served per employee. Although we operate in a low-density population area, in 2002, we served 461 customers per employee, about 40 percent more than the national average of 337, according to the most recent data available. We have continued our focus on productivity, efficiency and process improvement. Also, our open work environment, where no one has a private office, is becoming a model for other old-line businesses that are reinventing their work processes and creating a new corporate culture.

wondered, but not aloud, why they had chosen to spend a perfectly fine September day trying to tame a wilderness. As they

Comparison of 5 Year Cumulative Total Return*

** $100 invested on 12/31/97 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.*



To serve all our customers successfully, we must have internal talent that is capable of exceeding customers' expectations. We believe our workforce is fully capable of exceptional performance, and we reward their hard work appropriately. Green Mountain Power is one of very few utilities in the country to give every employee stock options. Every employee is expected to perform as if he or she were the owner of the Company, and stock options give meaning to that concept.

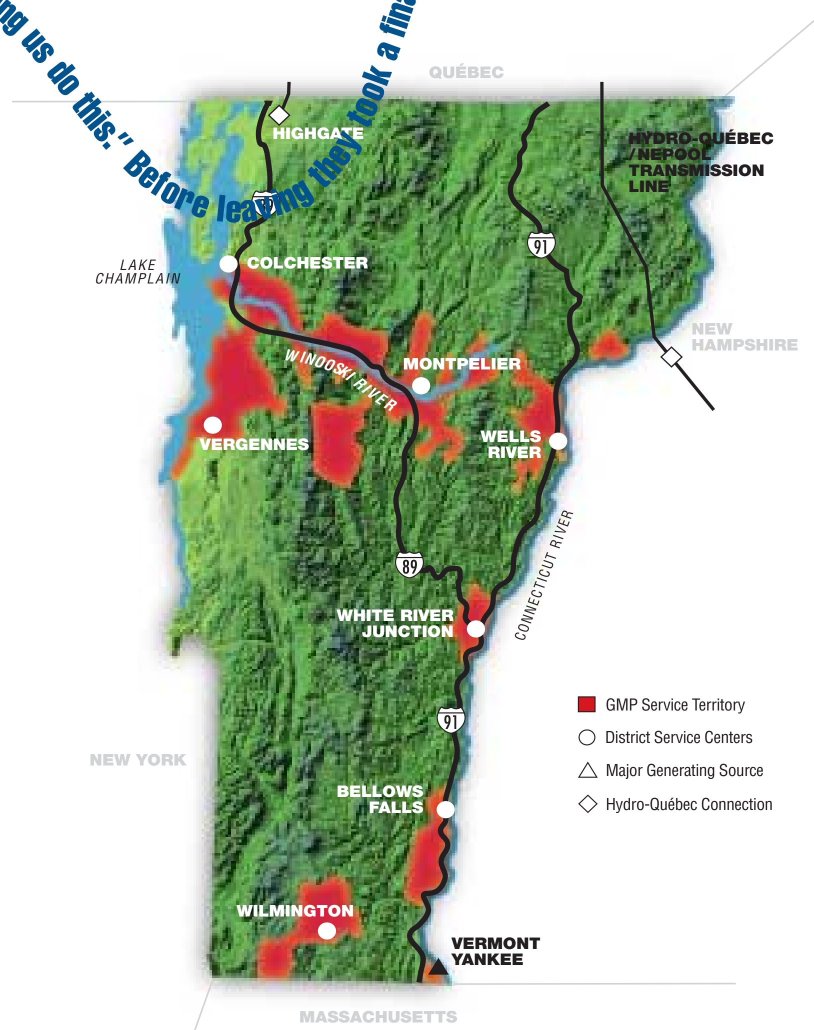
There is no doubt that significant challenges remain. Growth in northwestern Vermont is straining the transmission system. Peak summer demand has increased nine percent since 1999 and is now equal to the winter demand. No major additions have been made to the transmission system for about 20 years. To maintain adequate reliability Vermont Electric Power Company (VELCO), Vermont's statewide transmission organization, will need to expand the utility infrastructure in northwestern Vermont. We believe the most cost effective and reliable solution will be to upgrade VELCO's transmission lines, a process that will take at least five years to complete and will require working closely with customers and regulators.

Several significant additions were made to the Green Mountain Power team in 2002. Early in the year, Donald J. Rendall joined us as General Counsel. He had represented Green Mountain Power for several years as outside counsel, and we are grateful to have his talents available to us full-time. Green Mountain

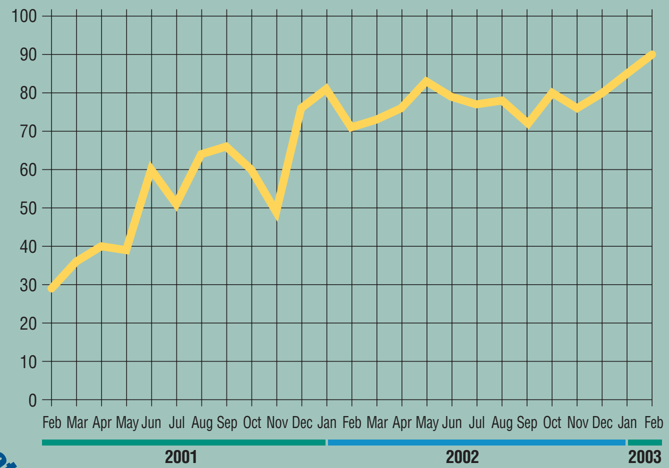
GMP's Energy Sources 2002

Hydro:	
Hydro-Québec	32.8%
NYPA	0.1
GMP Owned	5.0
	37.9
Nuclear:	
Vermont Yankee	34.9
Market Purchases:	16.2
Qualifying Facilities:	
Hydro	2.9
Ryegate (wood)	2.7
	5.6
Natural Gas:	
MMWEC	2.5
Oil:	
Wyman	0.2
GT&D	0.2
MMWEC	1.1
	1.5
Wood:	
McNeil	0.9
Wind:	
Searsburg	0.5
TOTAL	100.0%

packed up, though, the crew turned to CEO Chris Dutton, and said "Thanks for letting us do this." Before leaving they took a final look at the old path with its dangerous overhang,



Percent Calls Answered in Less Than 20 Seconds



and they were thrilled to think that even though few would know the bad spot had existed, no hiker would have to wonder if this trail was passable.

Power's Board of Directors has been strengthened by the addition of Elizabeth A. Bankowski, a business consultant in the area of corporate social responsibility, as a new member. Nordahl L. Brue, a lawyer and entrepreneur who has been a member of the Board for ten years, became Chair of the Board in May, after former Chair Thomas P. Salmon retired. In 2002, we replaced Arthur Andersen LLP as independent auditor with Deloitte & Touche LLP.

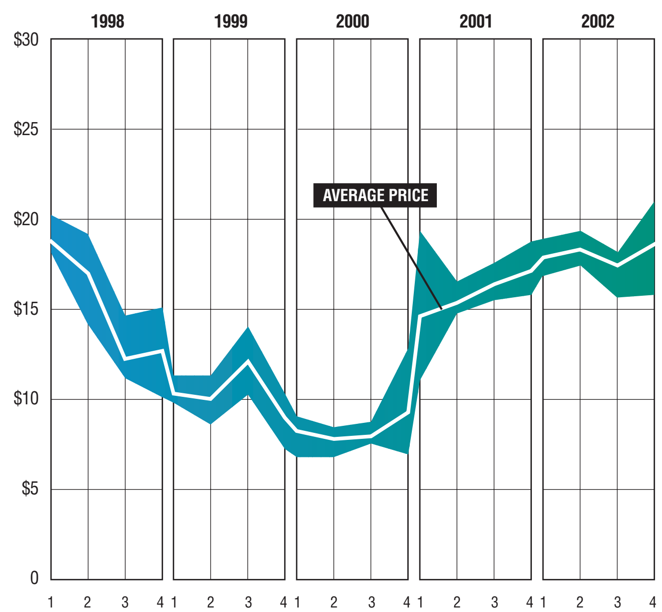
At Green Mountain Power's 2002 annual meeting in May, Vermont Gov. Howard Dean expressed very succinctly the state of Green Mountain Power, saying, "Not only has the leadership in this Company taken the initiative and done some extraordinary things, but this Company is thriving. It's doing exceptionally well. They have completely turned themselves around and their stock price reflects that." We pledge to continue the effort, innovation and dedication that have brought us this far on the path to prosperity.

Nordahl. L. Brue
Chairman

Christopher L. Dutton
President and Chief Executive Officer

March 6, 2003

Quarterly Stock Market Price Data



2002 ending stock price was $20.97.

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 1998 through 2002, as reported by the New York Stock Exchange. The number of registered shareholders of common stock as of December 31, 2002 was 5,233.

		Stock Price		Dividend
		High	Low	Declared
2002	First Quarter	$19.00	$17.00	13.75¢
	Second Quarter	19.50	17.54	13.75
	Third Quarter	18.24	15.75	13.75
	Fourth Quarter	21.08	15.89	19.00
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

Board of Directors

Elizabeth A. Bankowski, 55, elected 2002, business consultant in corporate social responsibility; Brattleboro, Vermont.

Nordahl L. Brue, 58, elected 1992, Chairman Franklin Foods Inc., Chairman PKC Corporation; Principal Champlain Management Services, Inc.; Burlington, Vermont.

William H. Bruett, 59, 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, 56, elected 1988, President and CEO of The Simpata Group; San Francisco, California.

Lorraine E. Chickering, 52, elected 1994, former President of Public Communications of Bell Atlantic Corporation; Silver Springs, Maryland.

John V. Cleary, 74, elected 1980, retired President and Chief Executive Officer, GMP; Boynton Beach, Florida.

David R. Coates, 65, elected 1999, Executive Vice President, New England Culinary Institute; retired Partner, KPMG Peat Marwick; Burlington, Vermont.

Christopher L. Dutton, 54, elected 1997, President, Chief Executive Officer and Chairman of the Executive Committee of GMP; Colchester, Vermont.

Euclid A. Irving, 50, 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

Donald J. Rendall, Jr.
Vice President, General Counsel
and Corporate Secretary

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
John V. Cleary
David R. Coates

Compensation Committee
Merrill O. Burns, Chair
Elizabeth A. Bankowski
Lorraine E. Chickering
Euclid A. Irving

Executive Committee
Christopher L. Dutton, Chair
Nordahl L. Brue
William H. Bruett
David R. Coates

Governance Committee
William H. Bruett, Chair
Elizabeth A. Bankowski
Nordahl L. Brue
Lorraine E. Chickering
John V. Cleary

Strategic Issues Committee
Nordahl L. Brue, Chair
Lorraine E. Chickering
David R. Coates
Euclid A. Irving

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.

Our critical accounting policies are discussed in "Market Risk and Other Risk Factors," and in Note A, "Significant Accounting Policies". Management believes the most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate and the manner in which we account for certain power supply arrangements that qualify as derivatives. These accounting policies, among others, affect the Company's more significant judgments and estimates used in the preparation of its consolidated financial statements.

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 "Power Contract Commitments", "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;
- changes in regional market and transmission rules;
- energy supply and demand and pricing;
- contractual commitments;
- availability, terms, and use of capital;
- general economic and business environment;
- changes in technology;
- 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 $1.98 per share of common stock, diluted, in 2002, compared to earnings of $1.85 per share in 2001 and a loss of $1.25 per share in 2000. The 2002 earnings represent a consolidated return on average common equity of 11.03 percent, and a return on regulated operations of 11.25 percent. The consolidated return on average common equity was 11.02 percent in 2001 and negative 7.1 percent in 2000. Income from continuing operations was $1.96 per share, diluted, in 2002, compared with $1.88 per share, diluted, in 2001, and a loss of $0.06 per share in 2000. The Company's subsidiary Northern Water Resources, Inc. ("NWR"), classified as discontinued in 1999, earned $0.02 per share in 2002, compared with a loss of $0.03 per share in 2001, and a loss of $1.19 per share in 2000. A significant portion of NWR's assets, which consisted of energy generation and efficiency investments and wastewater treatment projects, have been sold, or otherwise disposed. NWR's 2002 earnings resulted primarily from an adjustment to a reserve for warranty claims.

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 "VJO Contract"). The Settlement Order paved the way for restoration of the Company's first mortgage bond credit rating to investment grade status in 2001 (See "Rates-Retail Rate Cases" and "Liquidity and Capital Resources" in this section) and enabled the Company to earn its allowed rate of return of 11.25 percent on regulated operations during 2002 and 2001.

The improvement in earnings from continuing operations in 2002 compared with 2001 resulted from reductions in the Company's cost of capital and other operating expenses, partially offset by increases in maintenance and transmission expenses and lower gross margins on the Company's sales. Lower capital costs resulted from reduced interest rates and average debt levels, which caused 2002 interest expense to decline by $0.9 million compared to 2001, and the redemption of preferred stock which reduced 2002 preferred stock dividends $0.8 million compared with 2001. Lower gross margins resulted from an increase in power supply costs to serve retail customers that was only partially offset by recognition of $4.4 million in revenue deferred from 2001 under the Settlement Order.

The improvement in earnings from continuing operations in 2001, compared with 2000, resulted primarily from several factors, including:

- 2001 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 Québec, 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 2001 retail operating revenues; and
- the write-off in 2000 of $3.2 million, or $0.35 per share, in regulatory litigation costs.

Market Risk and Other Risk Factors

Power Supply Risk—Our material power supply contracts and arrangements are principally with Hydro Québec, MS and Vermont Yankee Nuclear Power Corporation. At December 31, 2002, more than 90 percent of our estimated load requirements through 2006 are expected to be met by these contracts and arrangements, and by our own generation and other power supply resources, which reduces the Company's exposure to market prices.

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

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

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 prices for fossil fuel resources or specified prices for contracted resources and then sells to us at a fixed rate to serve pre-established load requirements. This contract, along with other power supply commitments, allows the Company 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 No. 133 ("SFAS 133") and is effective through December 31, 2006. Management's estimate of the fair value of the future net benefit of this arrangement at December 31, 2002 is approximately $8.8 million. Assumptions used to calculate the future net benefit using the Black's option valuation model include a risk-free interest rate of 3.4 percent, volatility equivalent to a weighted average from NEPOOL, which varies from 32 percent in the first year to 29 percent in the fourth year, locked in forward commitment prices for 2003, with an estimated forward market price of approximately $43 per MWh for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Actual results may differ materially from the table below.

We currently have an arrangement that grants Hydro-Québec an option ("9701") to call power at prices that are expected to be below 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, 2002 is approximately $27.2 million. We sometimes use futures contracts to hedge forecasted sales of electric power under 9701.

A sensitivity analysis has been prepared to estimate exposure to the market price risk of 9701, using the Black-Scholes model, over the next 13 years. Assumptions used within the model include a risk-free interest rate of 5.02 percent, volatility equivalent to the weighted average from NEPOOL, which varies from 48 percent in the first year to 26 percent in year 13, locked in forward commitment prices for 2003, and an average of approximately 59,326 MWh per year, with an estimated forward market price of $59.81 per MWh for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Quoted forward market prices for monthly peak power rates are not currently available beyond 2004. 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 $0.9 million.

Commodity Price Risk	At December 31, 2002	
	Fair Value	Market Risk
	(In thousands)	
Net short position	$18,405	$880

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.

Regulatory Risk—There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont. However, if Vermont adopted such restructuring, the major risk factors for the Company that may arise 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 by the Company of its stranded costs of between $203 million and $224 million over the life of the contracts.

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 in Vermont have been based on a utility's cost of service. As a result, Vermont electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards No. 71 ("SFAS 71"), Accounting for the Effects of Certain Types of Regulation, allows regulated entities, including the Company, in appropriate circumstances, to establish regulatory assets and liabilities, and thereby defer the income statement impact of certain costs and revenues that are expected to be realized in future rates.

Regulatory assets represent incurred costs that have been deferred because the Company has concluded that they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs. The Company's last retail rate case was filed during 1998. Since that time a material amount of expenditures have been deferred as regulatory assets pending consideration by the VPSB in a future retail rate proceeding. These regulatory assets have been judged as probable of recovery by management. The most significant regulatory assets that are not being currently amortized in rates, or are being amortized at amounts that could materially differ from future expenditure levels, include:

Regulatory Assets	At December 31,	
	2002	2001
	(In thousands)	
Pine Street Barge Canal	$13,019	$12,425
Unscheduled VY Outage Costs	2,002	—
Demand Side Management	6,434	6,961
Storm Damages	1,905	2,169
Tree Trimming	905	905
Regulatory Assets	$24,265	$22,460

Management's conclusion that these assets are probable of recovery is based on a variety of factors, including benefits to customers, consistency with past regulatory treatment, materiality of costs relative to normal cost levels, similar rate case decisions in other jurisdictions applying cost of service ratemaking principles, and opportunities to recover these costs over extended periods of time. If the VPSB were to disallow any of these costs, the result would be a pretax charge to current earnings in the amount of the disallowance.

The Company currently complies with the provisions of SFAS 71. If the Company had determined that it no longer met the criteria for following SFAS 71, at December 31, 2002 the accounting impact would have been an extraordinary non-cash charge to operations of $51.6 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. However, we believe that the continued application of SFAS 71 is appropriate at this time.

We cannot predict whether restructuring legislation, if 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.

Pension Risk—Other critical accounting policies involve the noncontributory defined benefit pension and postretirement health care benefit plans of the Company. The reported costs of these plans are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension and postretirement health care costs are impacted by actual employee demographics, the level of Company contributions to the plans, earnings on plan assets, and health care cost trends (postretirement health care plan only).

The Company's pension and postretirement health care benefit plan assets consist of equity and fixed income investments. Fluctuations in equity market returns, as well as changes in general interest rates, may result in increased or decreased costs in future periods. Changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded defined benefit plan costs. For example, the Company in 2003 expects to reduce the expected return on its plan assets by 50 basis points to 8.5 percent, resulting in a $210,000 increase in plan expense. See Note H for further information.

As a result of our plan asset experience, at December 31, 2002, the Company was required to recognize an additional minimum liability of $2.4 million, net of applicable income taxes, as prescribed by SFAS 87. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income ("OCI"), and did not affect net income for 2002. The charge to OCI may be restored through common equity in future periods to the extent fair value of trust assets exceeded the accumulated benefit obligation. Current changes to plan assumptions, along with plan losses experienced during 2002, are expected to result in increased pension and postretirement health benefit expenses of approximately $0.6 million and $0.5 million, respectively, for 2003 compared with 2002.

Unregulated Businesses

Most of the assets of NWR, which invested in energy generation, energy efficiency and wastewater treatment projects, have been sold. NWR earned $0.1 million in 2002, compared with a loss of approximately $0.2 million in 2001, and a loss of $6.5 million in 2000. The 2002 earnings and 2001 loss resulted primarily from provisions to recognize adjustments to liability estimates under warranties 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 2002, essentially unchanged from the prior two years.

Results of Operations

Operating Revenues and MWh Sales—Operating revenues and megawatthour ("MWh") sales for the years ended 2002, 2001 and 2000 consisted of:

	Years ended December 31,		
	2002	2001	2000
	(Dollars in thousands)		
Operating Revenues:			
Retail	$201,052	$195,093	$185,944
Sales for Resale	70,646	83,804	88,333
Other	2,910	4,567	3,049
Total Operating Revenues	$274,608	$283,464	$277,326
MWH Sales—Retail	1,948,190	1,953,154	1,947,857
MWH Sales for Resale	2,107,941	2,368,887	2,575,657
Total MWH Sales	4,056,131	4,322,041	4,523,514

Average Number of Customers	Years ended December 31,		
	2002	2001	2000
Residential	73,861	73,249	72,424
Commercial and Industrial	13,194	13,006	12,769
Other	65	65	65
Total Number of Customers	87,120	86,320	85,258

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

Change in Operating Revenues	2001 to 2002	2000 to 2001
	(In thousands)	
Retail Rates	$ 6,471	$ 8,620
Retail Sales Volume	(512)	529
Resales and Other Revenues	(14,815)	(3,011)
Increase (Decrease) in Operating Revenues	($ 8,856)	$ 6,138

In 2002, total electricity sales decreased 6.2 percent compared with 2001, due to reduced sales for resale under the 9701 arrangement with Hydro-Québec and our MS contract, described in more detail below under the headings "Power Supply Expenses" and "Power Contract Commitments". Total operating revenues decreased $8.9 million, or 3.1 percent, in 2002 compared with 2001, due to decreases in sales for resale, partially offset by increased retail operating revenues. Retail operating revenues increased $6.0 million, or 3.1 percent, in 2002 compared with 2001 due to the recognition of $4.4 million of revenue deferred under the Settlement Order. Increased sales to residential and commercial customers also contributed to higher retail revenues, partially offset by a decline in revenues from International Business Machines Corporation ("IBM").

In 2001, total electricity sales decreased 4.5 percent compared with 2000, due principally to reduced sales for resale executed pursuant to the MS contract, 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 contract with that customer approved in the Settlement Order.

IBM, the Company's largest customer, operates a manufacturing facility in Essex Junction, Vermont. IBM's electricity requirements for its facility accounted for approximately 25.7, 26.6, and 26.6 percent of the Company's retail MWh sales in 2002, 2001, and 2000, respectively, and 17.3, 19.2, and 16.5 percent of the Company's retail operating revenues in 2002, 2001, and 2000, 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. During 2002, the VPSB approved a modification of this agreement for the last year of the term, 2003. The price of power for the three year term of the agreement is above our marginal costs of providing incremental service to IBM.

IBM reduced its Vermont workforce by 1,500 during 2002, to a level of approximately 7,000 employees. If future significant losses in electricity sales to IBM were to occur, the Company's earnings could be impacted adversely. If earnings were materially reduced as a result of lower retail sales, the Company would seek a retail rate increase from the VPSB. The Company is not aware of any plans by IBM to further reduce production at its Vermont facility. The Company currently estimates, based on a number of projected variables, the retail rate increase required from all retail customers by a hypothetical shutdown of the IBM facility to be in the range of five to ten percent, inclusive of projected declines in sales to residential and commercial customers.

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 Company recognized approximately $4.4 million of these revenues in 2002 and expects to recognize the remaining balance of $4.1 million during 2003. The deferred recognition of rate levelization revenues allowed the Company to achieve our allowed rate of return in 2002 without further rate relief and is expected to provide the Company with the opportunity to achieve similar operating results in 2003 without further rate relief (See "Power Contract Commitments", and "Rates-Retail Rate Cases" in this section).

Power supply expenses constituted 74.5, 75.3, and 77.7 percent of total operating expenses for the years 2002, 2001, and 2000, respectively. Power supply expenses decreased by $7.6 million or 3.8 percent in 2002 when compared with 2001, and resulted from the following:

- a $13.2 million decrease in power purchased for resale, primarily under the 9701 arrangement with Hydro-Québec and our MS contract;
- a $3.5 million decrease in the net cost of the 9701 arrangement with Hydro-Québec; and
- a $2.1 million increase in the value of additional generation at the Company's hydroelectric plants, that allowed the Company to purchase less power during 2002.

These decreases were partially offset by increased power supply expense in 2002 when compared with 2001 for the following reasons:

- a $6.2 million increase in the cost of power purchased from MS;
- a $3.7 million net increase in the cost of power purchased from Vermont Yankee, including an offset of $1.4 million for the increase in value of additional generation purchased from the plant; and
- a $2.9 million increase in power purchased from independent power producers.

Power supply expenses decreased by $10.5 million or 5.0 percent in 2001 when compared with 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 are 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 in power purchased for resale, primarily under a power supply contract discussed under the caption "Power Contract Commitments" below, pursuant to which the Company purchases 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.

In 2001, 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 expenses during 2000, $2.1 million in higher energy prices in 2001 under our MS contract, and higher capacity costs in 2001 of approximately $1.0 million.

The Independent System Operator of New England ("ISO" or "ISO New England") 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 the 9701 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 markets continue to experience the volatility evident since 1999, or the Company's power resources are unavailable during periods of high market prices, 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") between the Company and MS defines the general contract terms under which the parties may transact. 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 August 2002, the PPSA was modified and extended to December 31, 2006.

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 typically incorporate a risk premium.

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.

Pursuant to the 1987 Contract, Hydro-Québec 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 has the contractual right to delay any such reduction by one year under the 1987 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.

Our contracts with Hydro-Québec contain cross default provisions that allow Hydro-Québec to invoke "step-up" provisions under which the other Vermont utilities that are party to the contract would be required to purchase their proportionate share of the power supply entitlement of the defaulting utility. The Company is not aware of any instance where this provision has been invoked by Hydro-Québec.

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 was extended to 2003), 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.

Under the 9701 arrangement established in December 1997, 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, 2002, Hydro-Québec had purchased or called to purchase 458,000 MWh under option B.

In 2002, Hydro-Québec exercised option A and called for deliveries to third parties at a net expense to the Company of approximately $3.0 million, including capacity charges.

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 $6.5 million, including capacity charges.

In 2000, Hydro-Québec exercised option A and option B, and called for deliveries to third parties at a net expense 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 in 2000.

The Company believes that it is probable that Hydro-Québec will call options A and B for 2003, and has purchased replacement power at a net cost of $4.7 million.

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 Contract during the 1998 ice storm. The Company is a member of 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 July 31, 2002, Vermont Yankee completed the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy"). In addition to the sale of the generating plant, the transaction calls for Entergy through its power contract with VY, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of the Company's energy requirements. The Company continues to own approximately 19 percent of the common stock of VY. Our benefits of the plant sale and the VY power contract with Entergy include:

- VY receives cash approximately equal to the book value of the plant assets, removing the potential for stranded costs associated with the plant.
- VY and its owners will no longer bear operating risks associated with running the plant.
- VY and its owners will no longer bear the risks associated with the eventual decommissioning of the plant.
- Prices under the Power Purchase Agreement between VY and Entergy (the "PPA") range from $39 to $45 per megawatt-hour for the period beginning January 2003, substantially lower than the forecasted cost of continued ownership and operation by VY. Contract prices ranged from $49 to $55 for 2002, higher than the forecasted cost of continued ownership for 2002.
- The PPA calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, the contract prices are not adjusted upward.

The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the Entergy plant.

Payments totaling $0.5 million were made to VY's non-Vermont sponsors in return for guarantees those sponsors made to Entergy to finalize the VY sale.

Although the sale closed on July 31, 2002, the Company's distribution of the sale proceeds and final accounting for the sale are pending certain regulatory approvals and the resolution of certain closing items between VY and Entergy. The Company expects its share of the VY power plant sale proceeds, estimated at between $7 million and $8 million, to be distributed in the latter part of 2003.

The sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervenor parties to the VPSB approval proceeding appealed the VPSB approval to the Vermont Supreme Court. That appeal is pending. If the appellants prevail on their appeal, the VPSB could be required to conduct additional proceedings or to reconsider its order approving the sale.

Other Operating Expenses—Other operating expenses decreased $1.7 million, or 10.9 percent in 2002 compared with 2001. The decrease was primarily due to reduced consulting costs of approximately $1.0 million and reduced distribution expenses of $0.6 million. Other operating expenses are not expected to increase significantly during 2003.

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.

Transmission Expenses—Transmission expenses increased $1.1 million, or 7.7 percent, in 2002 compared with 2001. The Company's relative share of transmission costs varies with the peak demand recorded on Vermont's transmission system. The Company's share of those costs increased due to its increased load growth, relative to other Vermont utilities, and also because of increased transmission investment by VELCO.

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

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

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

During 2002, ISO New England and the New York Independent System Operator filed and then withdrew their petition with the FERC proposing to establish a single Northeastern Regional Transmission Organization ("NERTO") encompassing the six New England states and New York. ISO New England has indicated an intention to file a petition with FERC to create a regional transmission organization comprising six New England states now part of the ISO.

VELCO has proposed a project to substantially upgrade Vermont's transmission system (the "Northwest Reliability Project"), principally to support reliability and eliminate transmission constraints in northwestern Vermont, including most of the Company's service territory. The proposed Northwest Reliability Project must be approved by the VPSB. If approved, the project is estimated to cost approximately $150 million over a seven to ten year period. Under current NEPOOL and ISO New England rules, which require qualifying large transmission project costs to be shared among all New England utilities, the Company would expect the costs of this project to be allocated throughout the New England region, with Vermont utilities responsible for approximately five percent of the total project costs. However, in response to FERC's SMD NOPR and as part of ISO New England's SMD plan, ISO New England is considering changes to the transmission cost allocation rules which could modify or eliminate the opportunity to allocate costs associated with the Northwest Reliability Project to the New England region as a whole. The Company has vigorously advocated for continuation of the current cost allocation rules. If these rules are modified or eliminated, the Company and other Vermont utilities could be required to bear a greater proportion, and potentially all, of the cost of the Northwest Reliability Project.

Maintenance Expenses—Maintenance expenses increased $1.7 million or 25.0 percent in 2002 compared with 2001, due to increased expenditures related to storm damage and increased right-of-way maintenance programs.

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.

Depreciation and Amortization—Depreciation and amortization expense decreased $0.1 million or 1.0 percent in 2002 compared with 2001 due to reductions in depreciation of utility plant in service, partially offset by increased amortization of software costs.

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.

Income Taxes—Income tax expense decreased $0.9 million in 2002 compared with 2001 due to a decrease in the Company's taxable income. Income tax expense increased $7.6 million in 2001 when compared with that of 2000 due to an increase in the Company's taxable income.

Other Income—Other income increased $0.4 million in 2002 compared with 2001 due primarily to the VY recognition of deferred tax assets arising in conjunction with the sale of the VY plant, offset in part by payments made to out-of-state VY sponsors necessary to close the sale of the VY plant.

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.

Interest Expense—Interest expense decreased $0.9 million or 12.3 percent in 2002 compared with 2001 primarily due to scheduled and early redemptions of long-term debt and reduced short-term borrowing rates offset in part by higher average balances for short-term borrowings. Interest expense on long term debt is expected to rise approximately $0.9 million in 2003 due to increased average debt levels from long-term bonds issued in December 2002.

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.

Dividends on Preferred Stock—Dividends on preferred stock decreased $0.8 million or 90 percent in 2002 compared with 2001 due to the repurchase of all outstanding preferred stock other than the 4.75 percent Class B shares. Dividends on preferred stock are expected to be negligible during 2003. See the discussion under the caption, "Liquidity and Capital Resources-Financing and Capitalization".

Dividends on preferred stock decreased $81,000 or 8.0 percent in 2001 compared with 2000 due to repurchases of preferred stock.

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, 2002, our total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $27.2 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 waiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals 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 $13.0 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 some other jurisdictions, "sharing" has been accomplished by allowing utilities to recover costs over time without a rate of return. 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 Barge Canal site 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.

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, adjusted for inflation; and
- The Company's further investment in non-utility operations is restricted.

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

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.

The VPSB, in its order approving VY's sale of its nuclear power plant to Entergy, ordered the Company and Central Vermont Public Service each to file on or before April 15, 2003, a cost-of-service study based on actual 2002 data, to enable the VPSB to determine whether an adjustment to rates is justified in 2003 or 2004. The Company believes this filing will support the Company's current rates and does not intend to request a rate increase or decrease when this filing is made. The VPSB could initiate an investigation of the Company's rates based on this filing, requiring the Company to complete a rate case, and the VPSB could order an adjustment to the Company's rates based on its findings and conclusions. If the VPSB ordered the Company to reduce its rates in 2003 or 2004, this could have a material adverse effect on our operating results, cash flows and ability to pay dividends at current levels.

Capital Expenditures	Generation	Transmission	Distribution	Conservation	Other*	Total Net Expenditures
	(Dollars in thousands and net of AFUDC and customer advances for construction)					
Actual:						
2000	$1,937	$ 348	$7,316	**	$5,876	$15,477
2001	2,323	1,219	8,567	**	3,529	15,638
2002	3,258	1,827	9,173	**	7,267	21,525
Forecasted:						
2003	$2,578	$3,200	$8,638	**	$8,088	$22,504

*Other includes$1.3 million in 2000, $1.5 million in 2001, $1.8 million in 2002, and an estimated $2.3 million in 2003 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.

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 2003 are as shown above.

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

Financing and Capitalization—Internally-generated funds provided approximately 49 percent, 100 percent, and 41 percent, of requirements for 2002, 2001 and 2000, respectively. The 2002 rate of internally generated funding requirements was reduced because of accelerated redemptions of preferred stock and common stock repurchases described in more detail below. Internally generated funds, after payment of dividends, provide capital requirements for construction, sinking funds and other requirements. We anticipate that for 2003, internally generated funds will provide approximately 71 percent of total capital requirements for regulated operations, the remainder to be derived from bank loans.

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”. We also own an equity interest in VELCO, which requires the Company to contribute capital when required and to pay a portion of VELCO’s operating costs.

At December 31, 2002, our capitalization consisted of 47.6 percent common equity and 52.4 percent long-term debt.

The Company has a $20.0 million 364-day revolving credit agreement with Fleet Financial Services (“Fleet”) joined by KeyBank National Association (“KeyBank”), expiring June 2003 (the “Fleet-Key Agreement”). The Fleet-Key Agreement is unsecured and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was $2.5 million outstanding with a weighted average rate of 4.25 percent on the Fleet-Key Agreement at December 31, 2002. There was no non-utility short-term debt outstanding at December 31, 2002 or 2001.

The Company negotiated a $12.0 million, two-year, unsecured loan agreement with Fleet, joined by KeyBank, on August 24, 2001. The $12.0 million loan was repaid on December 16, 2002.

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

During March and June 2002, the Company repurchased $11.0 and $1.0 million, respectively, of the 7.32 percent Class E preferred stock outstanding. On May 1, 2002, the Company redeemed $0.3 million of the 7.0 percent Class C preferred stock outstanding. During November 2002, the Company redeemed $0.2 million of the 9.375 percent Class D preferred stock outstanding.

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

See Note D, Preferred Stock, and Note F, Long Term Debt for additional information.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2003.

The credit ratings of the Company’s securities at December 31, 2002 are:

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

On August 29, 2002, Moody’s upgraded the Company’s senior secured debt rating to Baa1 from Baa2. The outlook for the rating is stable. On September 29, 2002, Fitch Ratings upgraded the rating of the Company’s first mortgage bonds to BBB+ from BBB, with a stable outlook. On September 23, 2002, Standard and Poor’s Ratings Services affirmed its BBB rating of the Company’s senior secured debt, with a stable outlook.

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

The following table presents a summary of certain material contractual obligations existing as of December 31, 2002.

Summary of certain material contractual obligations		Payments Due by Period			
	Total	2003	2004 and 2005	2006 and 2007	After 2007
			(In thousands)		
Long-term debt	$ 101,000	$ 8,000	$ —	$ 14,000	$ 79,000
Interest on long-term debt	72,797	7,047	13,068	12,068	40,614
Preferred stock	85	30	55	—	—
Capital lease obligations	5,287	407	814	814	3,252
Hydro-Québec power supply contracts	671,268	47,285	101,368	101,872	420,743
MS power supply contract	184,108	55,884	83,941	44,283	—
Vermont Yankee	296,908	36,308	64,421	64,130	132,050
Total	$1,331,454	$154,961	$263,667	$237,167	$675,659

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

The Company's funding policy is to make voluntary contributions to its defined benefit plans before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company made voluntary pension plan contributions totaling $1.0 million between September 1, 2002 and December 31, 2002. The Company plans to make additional voluntary contributions totaling $1.0 million before June 30, 2003. The Company's pension costs and cash funding requirements could increase in future years in the absence of recovery in the equity markets.

Other Regulatory Proceedings and Litigation—In a series of Vermont regulatory proceedings, the Company has agreed to undertake a process known as "distributed utility planning" as part of its transmission and distribution planning process. Distributed utility planning requires the Company to evaluate conservation-related alternatives and distributed generation alternatives to typical transmission and distribution capital investments. In certain circumstances, the Company may be required to implement conservation or distributed generation alternatives in lieu of, or in addition to, traditional transmission and distribution capital investments, where societal cost savings associated with conservation or distributed generation, including the costs associated with avoided electricity sales, justify the expenditures. The Company is uncertain of the potential magnitude of future spending requirements for this program, but note they could be material. Costs associated with conservation measures or distributed generation facilities not owned by the Company would be deferred as regulatory assets pending future rate proceedings.

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville Dam hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, complaining that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company has petitioned the VPSB to make additional dam improvements at the facility at an estimated cost of $350,000. The VPSB must approve the Company's petition before the proposed improvements can be implemented. This regulatory proceeding is pending and the Company is unable to predict whether the Company's petition will be approved or whether the VPSB will impose regulatory conditions or penalties.

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. Alternate forms of performance based regulation currently appear as possible intermediate steps towards deregulation. 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 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.

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase the Bellows Falls hydroelectric facility from a third party, and the associated distribution plant owned by the Company within the town. In March 2002, voters in Rockingham approved an article authorizing Rockingham to create a municipal utility by acting to acquire a municipal plant, which would include the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. 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 its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that neither our remaining customers or our shareholders effectively subsidize a Rockingham municipal utility.

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 as well as other asset retirement 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

	2002	2001	2000
	(In thousands, except per share data)		
Operating Revenues	**$274,608**	$283,464	$277,326
Operating Expenses			
Power Supply			
Vermont Yankee Nuclear Power Corporation	**35,252**	30,114	34,813
Company-owned generation	**5,067**	4,742	7,777
Purchases from others	**153,129**	166,209	168,947
Other operating	**14,188**	15,924	17,644
Transmission	**15,221**	14,130	14,237
Maintenance	**8,854**	7,108	6,633
Depreciation and amortization	**14,151**	14,294	15,304
Taxes other than income	**7,623**	7,536	7,402
Income taxes	**6,043**	6,948	(691)
Total operating expenses	**259,528**	267,005	272,066
Operating income	**15,080**	16,459	5,260
Other Income			
Equity in earnings of affiliates and non-utility operations	**2,777**	2,253	2,495
Allowance for equity funds used during construction	**233**	210	284
Other (deductions) income, net	**(525)**	(90)	(73)
Total other income	**2,485**	2,373	2,706
Income before interest charges	**17,565**	18,832	7,966
Interest Charges			
Long-term debt	**5,214**	6,073	6,499
Other	**1,059**	1,154	986
Allowance for borrowed funds used during construction	**(103)**	(188)	(228)
Total interest charges	**6,170**	7,039	7,257
Income before preferred dividends and discontinued operations	**11,395**	11,793	709
Dividends on preferred stock	**96**	933	1,014
Income (Loss) from continuing operations	**11,299**	10,860	(305)
Income (Loss) on disposal, including provisions for operating losses during phaseout period, net of applicable income taxes	**99**	(182)	(6,549)
Net Income (Loss) Applicable to Common Stock	**$ 11,398**	$ 10,678	($ 6,854)
Earnings per Share			
Basic earnings (loss) per share from continuing operations	**$ 2.02**	$ 1.93	($ 0.06)
Basic earnings (loss) per share from discontinued operations	**0.02**	(0.03)	(1.19)
Basic earnings (loss) per share	**$ 2.04**	$ 1.90	($ 1.25)
Diluted earnings (loss) per share from continuing operations	**$ 1.96**	$ 1.88	($ 0.06)
Diluted earnings (loss) per share from discontinued operations	**0.02**	(0.03)	(1.19)
Diluted earnings (loss) per share	**$ 1.98**	$ 1.85	($ 1.25)
Cash dividends declared per share	**$ 0.60**	$ 0.55	$ 0.55
Weighted average shares outstanding–basic	**5,592**	5,630	5,491
Weighted average equivalent shares outstanding–diluted	**5,756**	5,789	5,491

Consolidated Statements of Comprehensive Income

Net Income	**$ 11,398**	$ 10,678	($ 6,854)
Minimum pension liability adjustment, net of $1,612 related income tax	**(2,374)**	—	—
Other comprehensive income, net of tax	**$ 9,024**	$ 10,678	($ 6,854)

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

	2002	2001	2000
		(In thousands)	
Operating Activities:			
Net Income (Loss) before preferred dividends	**$ 11,494**	$ 11,611	($ 5,840)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	**14,151**	14,294	15,304
Dividends from associated companies less equity income	**415**	280	(26)
Allowance for funds used during construction	**(335)**	(398)	(512)
Amortization of deferred purchased power costs	**3,236**	3,767	5,575
Deferred income taxes	**2,430**	(2,167)	161
Provision for chargeoff of deferred regulatory asset	**—**	—	3,229
Deferred purchased power costs	**(2,003)**	1,126	(6,692)
Accrued purchased power contract option call	**—**	(8,276)	8,276
Adjustments to provision for loss on segment disposal	**(99)**	182	6,549
Arbitration costs recovered (deferred)	**—**	3,229	(3,184)
Rate levelization liability	**(4,483)**	8,527	—
Environmental and conservation deferrals, net	**(2,194)**	(3,380)	(2,073)
Changes in:			
Accounts receivable and accrued utility revenues	**(896)**	6,483	(3,987)
Prepayments, fuel and other current assets	**850**	300	(931)
Accounts payable and other current liabilities	**(55)**	128	(4,337)
Accrued income taxes payable and receivable	**5,010**	1,187	(372)
Other	**1,556**	(1,603)	(181)
Net cash provided by continuing operations	**29,077**	35,290	10,959
Net change in discontinued segment	**—**	(1,797)	245
Net cash provided by operating activities	**29,077**	33,493	11,204
Investing Activities:			
Construction expenditures	**(19,543)**	(12,963)	(13,853)
Investment in associated companies	**(392)**	—	—
Proceeds from subsidiary sales	**—**	—	6,000
Investment in non-utility property	**(206)**	(212)	(187)
Net cash used in investing activities	**(20,141)**	(13,175)	(8,040)
Financing Activities:			
Proceeds from issuance of long-term debt	**42,000**	—	—
Payments to acquire treasury stock	**(16,319)**	—	—
(Reduction in) Proceeds from term loan	**(12,000)**	12,000	—
Repurchase of preferred stock	**(12,536)**	(235)	(1,640)
Issuance of common stock	**1,037**	1,655	1,250
Proceeds (Purchases) of certificate of deposit	**—**	16,173	(15,437)
Power supply option obligations	**—**	(16,012)	15,419)
Reduction in long-term debt	**(13,322)**	(9,700)	(6,700)
Short-term debt, net	**2,500**	(15,500)	7,600
Cash dividends	**(3,393)**	(4,034)	(4,011)
Net cash used in financing activities	**(12,033)**	(15,653)	(3,520)
Net increase (decrease) in cash and cash equivalents	**(3,097)**	4,665	(356)
Cash and cash equivalents at beginning of period	**5,006**	341	696
Cash and Cash Equivalents at End of Period	**$ 1,909**	$ 5,006	$ 341
Supplemental Disclosure of Cash Flow Information:			
Cash paid year-to-date for:			
Interest (net of amounts capitalized)	**$ 6,048**	$ 6,936	$ 7,185
Income taxes	**2,349**	9,622	1,191
Supplemental Disclosure of Non-Cash Information:			
Minimum pension liability adjustment, net	**$ 2,374**	$ —	$ —

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

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • December 31

ASSETS	2002	2001
	(In thousands)	
Utility Plant		
Utility plant, at original cost	**$311,543**	$302,489
Less accumulated depreciation	**122,197**	119,054
Net utility plant	**189,346**	183,435
Property under capital lease	**5,287**	5,959
Construction work in progress	**8,896**	7,464
Total utility plant, net	**203,529**	196,858
Other Investments		
Associated companies, at equity	**14,101**	14,093
Other investments	**7,451**	6,852
Total other investments	**21,552**	20,945
Current Assets		
Cash and cash equivalents	**1,909**	5,006
Accounts receivable, less allowance for doubtful accounts of $547 and $613	**17,253**	17,111
Accrued utility revenues	**6,618**	5,864
Fuel, materials and supplies, at average cost	**3,349**	4,058
Prepayments	**1,901**	1,976
Income tax receivable	**—**	1,699
Other	**402**	469
Total current assets	**31,432**	36,183
Deferred Charges		
Demand side management programs	**6,434**	6,961
Purchased power costs	**2,323**	3,504
Pine Street Barge Canal	**13,019**	12,425
Power supply derivative deferral	**18,405**	37,313
Other	**11,413**	12,265
Total deferred charges	**51,594**	72,468
Non-Utility		
Other current assets	**8**	8
Property and equipment	**249**	250
Other assets	**738**	817
Total non-utility assets	**995**	1,075
Total Assets	**$309,102**	$327,529

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

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • December 31

CAPITALIZATION AND LIABILITIES	2002	2001
	(In thousands, except share data)	
Capitalization		
Common stock, $3.33⅓ par value, authorized 10,000,000 shares (issued 5,782,496 and 5,701,010)	$ 19,276	$ 19,004
Additional paid-in capital	75,347	74,581
Retained earnings	16,171	8,070
Accumulated other comprehensive income	(2,374)	—
Treasury stock, at cost (827,639 and 15,856 shares)	(16,698)	(378)
Total common stock equity	91,722	101,277
Redeemable cumulative preferred stock	55	12,325
Long-term debt, less current maturities	93,000	74,400
Total capitalization	184,777	188,002
Capital Lease Obligation	5,287	5,959
Current Liabilities		
Current maturities of preferred stock	30	235
Current maturities of long-term debt	8,000	9,700
Short-term debt	2,500	—
Accounts payable, trade, and accrued liabilities	7,431	7,237
Accounts payable to associated companies	8,940	8,361
Rate levelization liability	4 ,091	8,527
Customer deposits	898	971
Interest accrued	1,081	1,100
Other	5,520	2,945
Total current liabilities	38,491	39,076
Deferred Credits		
Power supply derivative liability	18,405	37,313
Accumulated deferred income taxes	26,471	23,759
Unamortized investment tax credits	3,130	3,413
Pine Street Barge Canal cleanup liability	8,833	10,059
Other	21,767	18,247
Total deferred credits	78,606	92,791
COMMITMENTS AND CONTINGENCIES		
Non-Utility		
Net liabilities of discontinued segment	1,941	1,701
Total non-utility liabilities	1,941	1,701
Total Capitalization and Liabilities	$309,102	$327,529

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

Consolidated Statements of Shareholders' Equity

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

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Comprehensive Other Income	Treasury Stock	Stock Equity
				(Dollars in thousands)			
BALANCE, December 31, 1999	**5,409,715**	**$18,085**	**$72,594**	**$10,344**	**$ —**	**($ 378)**	**$100,645**
Common Stock Issuance:							
DRIP and ESIP	157,790	526	764				609
Compensation Program:							
Restricted Shares	(809)	(3)	(37)				(40)
Net Loss				(5,840)			(5,840)
Other Comprehensive Income							
Common Stock Dividends				(2,997)			(2,997)
Preferred Stock Dividends				(1,014)			(1,014)
BALANCE, December 31, 2000	**5,566,696**	**18,608**	**73,321**	**493**	**—**	**(378)**	**92,044**
Common Stock Issuance:							
DRIP and ESIP	105,767	352	1,218				1,570
Compensation Programs:							
Restricted Shares and ISOP	12,691	44	42				86
Net Income				11,611			11,611
Other Comprehensive Income							
Common Stock Dividends				(3,101)			(3,101)
Preferred Stock Dividends				(933)			(933)
BALANCE, December 31, 2001	**5,685,154**	**19,004**	**74,581**	**8,070**	**—**	**(378)**	**101,277**
Common Stock Issuance:							
DRIP and ESIP	28,682	95	424				519
Common Stock Repurchase	(811,783)					(16,320)	(16,320)
Compensation Programs:							
Restricted Shares and ISOP	52,804	177	342				519
Net Income				11,494			11,494
Other Comprehensive Income (Loss)					(2,374)		(2,374)
Common Stock Dividends				(3,297)			(3,297)
Preferred Stock Dividends				(96)			(96)
BALANCE, December 31, 2002	**4,954,857**	**$19,276**	**$75,347**	**$16,171**	**($2,374)**	**($16,698)**	**$ 91,722**

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	Issued and Outstanding 2002	Issued and Outstanding 2001	2002 (In thousands)	2001 (In thousands)
Common Stock, $3.33⅓ par value	10,000,000	**4,954,857**	5,685,154	**$19,276**	$19,004

	Authorized	Issued	Outstanding Shares 2002	Outstanding Shares 2001	2002 (In thousands)	2001 (In thousands)
Redeemable Cumulative Preferred Stock, $100 par value						
4.75%, Class B, redeemable at $101 per share	15,000	15,000	**850**	1,150	**$85**	$ 115
7%, Class C	15,000	15,000	**—**	2,850	**—**	285
9.375%, Class D, Series	40,000	40,000	**—**	1,600	**—**	160
7.32%, Class E, Series	200,000	120,000	**—**	120,000	**—**	12,000
Total Preferred Stock					**$85**	$12,560

LONG-TERM DEBT	2002 (In thousands)	2001 (In thousands)
Fleet–Key Term Loan Due August 2003	$ **—**	$12,000
First Mortgage Bonds		
6.29% Series due 2002	**—**	8,000
6.41% Series due 2003	**8,000**	8,000
10.0% Series due 2004	**—**	5,100
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
6.04% Series due 2017—Cash sinking fund commences 2011	**42,000**	—
Total Long-term Debt Outstanding	**101,000**	84,100
Less Current Maturities (due within one year)	**8,000**	9,700
Total Long-term Debt, Less Current Maturities	**$93,000**	$74,400

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 retail sales in its regulated electric utility operation, which purchases and generates electric power and distributes it to approximately 88,000 customers. At December 31, 2002, the Company's primary unregulated subsidiary investment was Northern Water Resources, Inc. ("NWR"), 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. Green Mountain Power Investment Company ("GMPIC") was created in December 2002 to hold the Company's investments in Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VY") and Vermont Electric Power Company, Inc. ("VELCO"). 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, Green Mountain Propane Gas Company ("GMPG") and GMP Real Estate Corporation. The results of these subsidiaries, and the Company's unregulated rental water heater program, excluding NWR, 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, and the Company's unregulated water heater program, which earned approximately $0.3 million in 2002, is as follows:

	Years ended December 31,		
	2002	2001	2000
		(In thousands)	
Revenues	$997	$1,012	$1,034
Expenses	744	749	696
Net income	$253	$ 263	$ 338

The Company accounts for its investments in VY, 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.("SFAS") 71 ("SFAS 71"), "Accounting for Certain Types of Regulation". Under SFAS 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. 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,	
	2002	2001
	(In thousands)	
Power Supply Derivative	$18,405	$37,313
Pine Street Barge Canal	13,019	12,425
Power Supply	4,492	6,112
Demand Side Management	6,434	6,961
Preliminary Survey	1,202	1,094
Storm Damages	1,905	2,169
Regulatory Commission Costs	1,774	873
Tree Trimming	905	905
Restructuring Costs	2,216	3,502
Other	1,242	1,114
Total Deferred Charges	$51,594	$72,468

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 the Federal Energy Regulatory Commission ("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, 2002, 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.

The annual depreciation provision was approximately 3.2 percent at the beginning of 2002, 3.5 percent of total depreciable property at the beginning of 2001, and 3.5 percent at the beginning of 2000.

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. Revenue is recognized when electricity is delivered. The Company accrues utility revenues, based on estimates of electric service rendered and not billed at the end of an accounting period, in order to match revenues with related costs.

8. Deferred Charges

Prior to the sale of the Vermont Yankee ("VY") nuclear generating plant (See Note B), the Company deferred and amortized certain replacement power, maintenance and other costs associated with outages at the VY generation plant. In addition, the Company accrued and amortized 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 and other regulatory assets, in a manner consistent with authorized or expected ratemaking treatment.

Other deferred charges totaled $11.4 million and $12.3 million at December 31, 2002 and 2001, 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 2002 and 2001, the Company granted additional options of 80,300 and 56,450, respectively. See Note C for additional information.

SFAS 123 requires disclosure of pro-forma information regarding net income and earnings per share. The information presented below has been determined as if the Company accounted for its employee and director stock options under the fair value method of that statement.

Pro-forma net income (loss)	For the years ended December 31, 2002	2001	2000
	(In thousands, except per share amounts)		
Net income (loss) reported	$11,398	$10,678	($6,854)
Pro-forma net income (loss)	$11,246	$10,527	($6,911)
Net income (loss) per share			
As reported–basic	$2.04	$1.90	($1.25)
Pro-forma basic	$1.99	$1.87	($1.26)
As reported–diluted	$1.98	$1.85	($1.25)
Pro-forma diluted	$1.94	$1.82	($1.26)

10. Major Customers

The Company had one major retail customer, International Business Machines Corporation("IBM"), that accounted for 25.7 percent, 26.6 percent, and 26.6 percent of retail MWh sales, and 17.3 percent, 19.2 percent and 16.5 percent of the Company's retail operating revenues in 2002, 2001 and 2000, respectively.

11. Fair Value of Financial Instruments

The present value of the Company's first mortgage bonds and preferred stock outstanding, if refinanced using prevailing market rates of interest, would decrease from the balances outstanding at December 31, 2002 by approximately 4.7 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, 2002, the Company had other deferred credits and long-term liabilities of $21.8 million, consisting of reserves for damage claims and accruals for employee benefits, compared with a balance of $18.2 million at December 31, 2001.

13. Environmental Liabilities

The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. Only those site investigation, characterization and remediation costs currently known and determinable can be considered "probable and reasonably estimable" under SFAS 5, "Accounting for Contingencies". As costs become probable and reasonably estimable, reserves are adjusted as appropriate. As reserves are recorded, regulatory assets are recorded to the extent environmental expenditures are expected to be recovered in rates. Estimates are based on studies provided by third parties.

14. Income Taxes

The Company recognizes tax assets and liabilities according to SFAS 109, "Accounting for Income Taxes", for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of assets and liabilities. Investment tax credits associated with utility plant are deferred and amortized over the lives of the related assets. Valuation allowances are provided when necessary against certain deferred tax assets.

15. Purchased Power

The Company records the annual cost of power obtained under long-term contracts as operating expenses.

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 mitigate the risk of fossil fuel and spot market electricity price increases. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions.

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, 2002, the Company had a liability reflecting the net negative fair value of the two derivatives described below, as well as a corresponding regulatory asset, determined using the Black's or Black-Scholes option valuation method, of approximately $18.4 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, 2006. Management's estimate of the fair value of the future net benefit of this contract at December 31, 2002 is approximately $8.8 million.

We currently have an arrangement that grants Hydro-Québec an option ("9701") 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, 2002 is approximately $27.2 million. We use futures contracts to hedge the 9701 call option.

16. 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.

17. Reclassifications

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

18. New Accounting Standards

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 2002, goodwill and intangible assets deemed to have indefinite lives will no longer be amortized and will be subject to annual impairment tests. The application of these accounting standards does not materially impact the Company's 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 and other asset retirement costs. SFAS 143 prescribes fair value accounting for asset retirement liabilities, including nuclear decommissioning obligations, and requires recognition of such liabilities at the time incurred. The application of this accounting standard is not expected to materially impact the Company's 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 application of this accounting standard does not materially impact the Company's financial position or results of operations.

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

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

B Investments in Associated Companies

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

	Percent Ownership at December 31,		Investment in Equity at December 31,	
	2002	2001	2002	2001
			(In thousands)	
VELCO–Common	28.41%	29.50%	$ 2,309	$ 1,932
–Preferred	30.00%	30.00%	305	420
Total VELCO			2,614	2,352
Vermont Yankee–Common	18.99%	17.88%	9,721	9,725
New England Hydro-Transmission–Common	3.18%	3.18%	660	761
New England Hydro-Transmission Electric–Common	3.18%	3.18%	1,106	1,255
Total investment in associated companies			$14,101	$14,093

Undistributed earnings in associated companies totaled approximately $484,000 at December 31, 2002.

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 $12.7 million, $11.5 million, and $9.8 million for the years 2002, 2001 and 2000, respectively. Pursuant to VELCO's Amended Articles of Association, the Company is entitled to approximately 29 percent of the dividends distributed by VELCO. The Company has recorded its equity in earnings on this basis and also is obligated to provide its proportionate share of the equity capital requirements of VELCO through continuing purchases of its common stock, if necessary.

Summarized unaudited financial information for VELCO is as follows:

	At and for the years ended December 31,		
	2002	2001	2000
		(In thousands)	
Net income applicable to common stock	$ 1,094	$ 1,118	$ 1,257
Company's equity in net income	$ 319	$ 308	$ 395
Total assets	$106,613	$89,322	$82,123
Less:			
Liabilities and long-term debt	97,417	81,335	73,874
Net assets	$ 9,196	$ 7,987	$ 8,249
Company's equity in net assets	$ 2,614	$ 2,352	$ 2,456

Vermont Yankee

On July 31, 2002, Vermont Yankee ("VY") announced that the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy") had been completed. See Note K for further information concerning our long-term power contract with VY.

During May 2002, prior to the sale of the plant to Entergy, the VY plant had fuel rods that required repair, a maintenance requirement that is not unique to VY. VY closed the plant for a twelve-day period, beginning on May 11, 2002, to repair the rods. The Company's share of the cost for the repair, including incremental replacement energy costs, was approximately $2.0 million. The Company received an accounting order from the VPSB on August 2, 2002, allowing it to defer the additional costs related to the outage, and believes that such amounts are probable of future recovery.

The Company's ownership share of VY has increased from approximately 17.9 percent in 2001 to approximately 19.0 percent currently, due to VY's purchase of certain minority shareholders' interests. The Company's entitlement to energy produced by the Entergy Vermont Yankee nuclear plant has increased from approximately 18 percent to 20 percent of plant production through a series of transactions in connection with the sale of the plant to Entergy.

The increase in equity in earnings of VY resulted from VY's recognition of certain deferred tax assets as a result of the sale of the nuclear plant.

Summarized unaudited financial information for Vermont Yankee is as follows:

	At and for the years ended December 31,		
	2002	2001	2000
		(In thousands)	
Earnings:			
Operating revenues	$175,722	$178,840	$178,294
Net income applicable to common stock	$ 9,454	$ 6,119	$ 6,583
Company's equity in net income	$ 1,745	$ 1,131	$ 1,177
Total assets	$201,616	$723,815	$706,984
Less:			
Liabilities and long-term debt	150,413	669,640	652,663
Net assets	$ 51,203	$ 54,175	$ 54,321
Company's equity in net assets	$ 9,721	$ 9,725	$ 9,713

C Common Stock Equity

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 416,328 shares were reserved and unissued at December 31, 2002. The Company also funds an Employee Savings and Investment Plan ("ESIP"). At December 31, 2002, there were 82,754 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.

The fair values of the options granted in 2002, 2001 and 2000 are $2.27 $4.16 and $2.03 per share, respectively. They were estimated at the grant date using the Black-Scholes option-pricing model. The following tables present information about the assumptions that were used for each plan year, and a summary of the options outstanding at December 31, 2002.

	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
Granted	80,300	$17.82	$16.78–17.83	
Exercised	53,250	8.12	7.90–16.78	
Forfeited	25,400	9.34	7.90–18.67	
Outstanding at 12/31/02	365,800	$11.23	$7.90–17.823	151,775

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

				Assumptions used in option pricing model			
Plan Year	Weighted Average Exercise Price	Outstanding Options	Remaining Contractual Life	Risk Free Interest Rate	Expected Life in Years	Expected Stock Volatility	Dividend Yield
2000	$ 7.90	236,900	7.6 years	6.05%	5	30.58	4.5%
2001	16.63	50,400	8.6 years	5.25%	6	32.69	4.0%
2002	17.37	78,500	9.6 years	4.50%	6.5	16.89	4.5%
	$11.14	365,800					

Reconciliation of net income available for common shareholders and average shares	For the years ended December 31, 2002	2001	2000
		(In thousands)	
Net income (loss) before preferred dividends	$11,494	$11,611	($5,840)
Preferred stock dividend requirement	96	933	1,014
Net income (loss) applicable to common stock	$11,398	$10,678	($6,854)
Average number of common shares–basic	5,592	5,630	5,491
Dilutive effect of stock options	164	159	—
Average number of common shares–diluted	5,756	5,789	5,491

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, became vested under this program during 2002, and no shares remain unvested or unissued at December 31, 2002.

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

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 $12.1 million of retained earnings were free of restrictions at December 31, 2002.

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, 2002, $220,000 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 and sinking fund requirements provided for any class of preferred stock.

The outstanding Class B preferred stock is subject to annual purchase and sinking fund requirements. The sinking fund requirement is mandatory. The purchase fund requirement is 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 outstanding Class B preferred stock is 300 shares in 2003 and 2004, and 250 shares in 2005.

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 three years are $30,000 each for 2003 and 2004, and $25,000 for 2005.

Class B preferred stock is 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 is $1.00 per share. During 2002, the Company repurchased all $12.0 million of the 7.32 percent Class E preferred stock outstanding. On May 1, 2002, the Company redeemed $0.3 million of the 7.0 percent Class C preferred stock outstanding. During November 2002, the Company redeemed the remaining $0.2 million of the 9.375 percent Class D preferred stock outstanding.

E Short-Term Debt

The Company has a $20.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by KeyBank National Association("KeyBank"), expiring June 2003 (the "Fleet-Key Agreement"). The Fleet-Key Agreement is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was $2.5 million outstanding at a weighted average rate of 4.25 percent under the Fleet-Key Agreement at December 31, 2002. There was no non-utility short-term debt outstanding at December 31, 2002 or 2001.

The Fleet-Key Agreement 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.

F Long-Term Debt

On December 16, 2002, the Company issued through private placement $42 million principal amount of first mortgage bonds bearing interest at 6.04 percent per year and maturing on December 1, 2017. The average duration of the bond issuance is twelve years and the bonds are subject to seven equal annual principal payments beginning on December 1, 2011. Proceeds were used to retire all of the Company's short and intermediate term debt, and to repurchase 811,783 shares of the Company's common stock.

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 7.0 percent and 7.1 percent at December 31, 2002 and 2001, 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, as of December 31, 2002, are:

	Sinking Fund and Maturities (In thousands)
2003	$ 8,000
2004	—
2005	—
2006	14,000
2007	—
Thereafter	79,000
Total long-term debt	$101,000

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

The Company executed and delivered a $12.0 million, two-year, unsecured loan agreement with Fleet, joined by KeyBank, on August 24, 2001. This $12.0 million loan was repaid on December 16, 2002.

On August 29, 2002, Moody's upgraded the Company's senior secured debt rating to Baa1 from Baa2. The outlook for the rating is stable. On September 29, 2002, Fitch Ratings upgraded the rating of the Company's first mortgage bonds to BBB+ from BBB, with a stable outlook. On September 23, 2002, Standard and Poor's Ratings Services affirmed its BBB rating of the Company's senior secured debt, with a stable outlook.

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, 2002 and 2001, the net regulatory assets were $1,042,000 and $1,096,000, 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, 2002 and December 31, 2001, were as follows:

	At December 31, 2002	2001
	(In thousands)	
Deferred Tax Assets		
Contributions in aid of construction	$11,130	$10,435
Deferred compensation and postretirement benefits	4,570	4,382
Self-insurance and other reserves	1,369	—
Other	3,032	5,525
	20,101	20,342
Deferred Tax Liabilities		
Property-related	41,967	39,518
Demand side management	1,870	2,059
Deferred purchased power costs	943	1,450
Pine Street reserve	1,792	855
Other	—	219
	46,572	44,101
Net accumulated deferred income tax liability	$26,471	$23,759

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, 2002	2001	2000
		(In thousands)	
Net change in deferred income tax liability	$ 2,712	($1,885)	$443
Change in income tax related regulatory assets and liabilities	2,759	(1,149)	184
Changes in alternative minimum tax credit	—	—	—
Change in tax effect of accumulated other comprehensive income	(1,612)	—	—
Deferred income tax expense (benefit)	$ 3,859	($3,034)	$627

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

	Years ended December 31, 2002	2001	2000
		(In thousands)	
Current federal income taxes	$1,873	$ 7,846	($ 786)
Current state income taxes	593	2,418	(249)
Total current income taxes	2,466	10,264	(1,035)
Deferred federal income taxes	2,920	(2,296)	461
Deferred state income taxes	939	(738)	166
Total deferred income taxes	3,859	(3,034)	627
Investment tax credits—net	(282)	(282)	(283)
Income tax provision (benefit)	$6,043	$ 6,948	($ 691)

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, 2002	2001	2000
		(Dollars in thousands)	
Income (loss) before income taxes and preferred dividends	$17,537	$18,559	($6,531)
Federal statutory rate	34.0%	35.0%	34.0%
Computed "expected" federal income taxes	5,963	6,496	(2,221)
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation	41	45	83
Dividends received and paid credit	(575)	(440)	(435)
AFUDC–equity funds	(80)	(72)	(33)
Amortization of ITC	(282)	(282)	(282)
State tax (benefit)	1,011	1,705	(83)
Excess deferred taxes	(60)	(60)	(60)
Taxes attributable to subsidiaries	(31)	63	2,213
Other	56	(507)	127
Total federal and state income tax (benefit)	$ 6,043	$ 6,948	($ 691)
Effective combined federal and state income tax rate	34.5%	37.4%	10.6%

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:

Nonutility excluding discontinued operations	Years ended December 31, 2002	2001	2000
		(In thousands)	
State income taxes	($1)	$—	$ 7
Federal income taxes	(3)	(1)	21
Income tax expense (benefit)	($4)	($ 1)	$28

The effective combined federal and state income tax rate for the continuing non-utility operations was approximately 40 percent for each of the years ended December 31, 2002, 2001 and 2000. See Note L for income tax information on the discontinued operations of NWR.

	At and for the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
	(In thousands)			
Change in projected benefit obligation:				
Projected benefit obligation as of prior year end	$25,895	$23,332	$ 16,491	$14,947
Service cost	668	537	296	241
Interest cost	1,849	1,737	1,119	1,043
Participant contributions	—	—	147	151
Change in actuarial assumptions	—	367	—	—
Actuarial (gain) loss	3,230	1,650	3,619	1,021
Benefits paid	(1,650)	(1,670)	(965)	(912)
Administrative expense	(55)	(58)	—	—
Projected benefit obligation as of year end	$29,937	$25,895	$ 20,707	$16,491
Change in plan assets:				
Fair value of plan assets as of prior year end	$24,341	$27,760	$ 10,016	$10,944
Administrative expenses paid	(55)	(58)	—	—
Participant contributions	—	—	147	151
Employer contributions	1,000	—	819	761
Actual return on plan assets	(2,532)	(1,691)	(1,257)	(928)
Benefits paid	(1,650)	(1,670)	(965)	(912)
Fair value of plan assets as of year end	$21,104	$24,341	$ 8,760	$10,016
Funded status as of year end	($8,833)	($1,554)	($11,948)	($6,475)
Unrecognized transition obligation (asset)	(77)	(241)	3,280	3,608
Unrecognized prior service cost	839	986	(462)	(519)
Unrecognized net actuarial (gain) loss	6,982	(892)	8,379	2,711
Accrued benefits at year end	($1,089)	($1,701)	($ 751)	($ 675)

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.

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

The Company's funding policy is to make voluntary contributions to its defined benefit plans before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company made voluntary pension plan contributions totaling $1.0 million between September 1, 2002 and December 31, 2002 and plans to make voluntary contributions totaling an additional $1.0 million by June 30, 2003. The Company's pension costs and cash funding requirements could increase in future years in the absence of recovery in the equity markets.

As a result of GMP's retirement plan asset return experience, at December 31, 2002, the Company has recognized an additional minimum liability of $2.4 million, net of applicable income taxes, as prescribed by generally accepted accounting principles. The liability is recorded as a reduction to common equity through a charge to other comprehensive income and did not affect net income for 2002.

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 postretirement health care plan to establish a 401-h sub-account and separate VEBA trusts for its union and non-union employees. The VEBA plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities. The table above provides a reconciliation of benefit obligations, plan assets, and funded status of the plans as of December 31, 2002 and 2001.

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31, 2002, 2001, and 2000 were $408,000, $340,000, and $346,000, 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		
	2002	2001	2000	2002	2001	2000
	(In thousands)					
Service cost	$ 668	$ 537	$ 655	$ 296	$ 241	$ 216
Interest cost	1,849	1,737	1,658	1,119	1,043	1,049
Expected return on plan assets	(2,112)	(2,379)	(2,580)	(851)	(892)	(940)
Amortization of transition asset	(164)	(164)	(164)	—	—	—
Amortization of prior service cost	147	147	121	(58)	(58)	(58)
Amortization of the transition obligation	—	—	—	328	328	328
Recognized net actuarial gain	—	(237)	(474)	60	—	—
Net periodic benefit cost (income)	$ 388	($ 359)	($ 784)	$ 894	$ 662	$ 595

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

	For the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Weighted average assumptions as of year end:				
Discount rate	6.50%	7.50%	6.50%	7.00%
Expected return on plan assets	9.00%	9.00%	8.50%	8.50%
Rate of compensation increase	4.25%	4.50%	4.25%	4.25%
Medical inflation	—	—	7.50%	8.00%

For measurement purposes, a 10.0 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2003. This rate of increase gradually declines to 5.5 percent in 2009. 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, 2002 by $3.4 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2002 by $257,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2002 by $2.7 million, and the total of the service and interest cost components of net periodic postretirement cost for 2002 by $202,000.

11 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 deregulation in Vermont. Alternative forms of performance-based regulation currently appear as possible intermediate steps towards deregulation. 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, 2002, the Company's total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $27.1 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 waiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier 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 $13.0 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. 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 request 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. Jointly-Owned Facilities

The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2002, as follows:

	Ownership Interest	Share of Capacity	Utility Plant	Accumulated Depreciation
	(In %)	(In MW)	(In thousands)	
Highgate	33.8	67.6	$10,296	$4,657
McNeil	11.0	5.9	8,989	5,078
Stony Brook (No. 1)	8.8	31.0	10,377	8,521
Wyman (No. 4)	1.1	6.8	1,980	1,318
Metallic Neutral Return	59.4	—	1,563	744

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.

4. 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.

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, adjusted for inflation; and
- The Company's further investment in non-utility operations is restricted.

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

The VPSB, in its order approving VY's sale of its nuclear power plant to Entergy, ordered the Company and Central Vermont Public Service each to file on or before April 15, 2003, a cost-of-service study based on actual 2002 data, to enable the VPSB to determine whether an adjustment to rates is justified in 2003 or 2004. The Company believes this filing will support the Company's current rates and does not intend to request a rate increase or decrease when this filing is made. The VPSB could initiate an investigation of the Company's rates based on this filing, requiring the Company to complete a rate case, and the VPSB could order an adjustment to the Company's rates based on its findings and conclusions. If the VPSB ordered the Company to reduce its rates in 2003 or 2004, this could have a material adverse effect on our operating results, cash flows and ability to pay dividends at current levels.

5. Other Deferred Charges Not Included in Rate Base

The Company has incurred and deferred approximately $11.1 million in costs for demand side conservation programs, tree trimming, storm damage, unscheduled VY outage costs 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 certain 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.

6. Competition

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures, and on March 5, 2002, voters in Rockingham authorized the town to establish its own electric utility, by acting to acquire 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 neither our remaining customers nor our shareholders subsidize Rockingham.

7. Other Legal Matters

In a series of Vermont regulatory proceedings, the Company has agreed to undertake a process known as "distributed utility planning" as part of its transmission and distribution planning process. Distributed utility planning requires the Company to evaluate conservation-related alternatives and distributed generation alternatives to typical transmission and distribution capital investments. In certain circumstances, the Company may be required to implement conservation or distributed generation alternatives in lieu of, or in addition to, traditional transmission and distribution capital investments, where societal cost savings associated with conservation or distributed generation, including the costs associated with avoided electricity sales, justify the expenditures. The Company is uncertain of the potential magnitude of future spending requirements for this program, but note they could be material. Costs associated with conservation measures or distributed generation facilities not owned by the Company would be deferred as regulatory assets pending future rate proceedings.

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville Dam hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, complaining that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company has petitioned the VPSB to make additional dam improvements at the facility at an estimated cost of $350,000. The VPSB must approve the Company's petition before the proposed improvements can be implemented. This regulatory proceeding is pending and the Company is unable to predict whether the Company's petition will be approved or whether the VPSB will impose regulatory conditions or penalties.

The Company is involved in other 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, 2002, the present value of the Company's obligation is approximately $5.3 million.

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

	Years ending December 31, (In thousands)
2003	$ 407
2004	407
2005	406
2006	407
2007	407
Total for 2008–2015	3,253
Total	$5,287

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 2002 follows:

	Stony Brook
	(Dollars in thousands)
Plant capacity	352.0 MW
Company's share of output	4.40%
Contract period expires:	2006
Company's annual share of:	
Interest	$ 140
Other debt service	435
Other capacity	306
Total annual capacity	$ 881
Company's share of long-term debt	$2,314

2. Vermont Yankee

The Company has a long-term power purchase contract with Vermont Yankee Nuclear Power Corporation, which sold its nuclear power plant to Entergy Nuclear Vermont Yankee on July 31, 2002. The Company is no longer required to pay its proportionate share of fixed costs associated with the Entergy plant, including when the plant is not operating, though the Company is responsible for finding replacement power at such times.

The VY sale of its nuclear power plant to Entergy also calls for Entergy, through its power contract with VY, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of the Company's energy requirements. The Company continues to own approximately 19 percent of the common stock of VY. Our benefits of the plant sale and the VY power contract with Entergy include:

- VY receives cash approximately equal to the book value of the plant assets, removing the potential for stranded costs associated with the plant.
- VY and its owners will no longer bear operating risks associated with running the plant.
- VY and its owners will no longer bear the risks associated with the eventual decommissioning of the plant.
- Prices under the Power Purchase Agreement between VY and Entergy (the "PPA") range from $39 to $45 per megawatt-hour for the period beginning January 2003, substantially lower than the forecasted cost of continued ownership and operation by VY. Contract prices ranged from $49 to $55 for 2002, higher than the forecasted cost of continued ownership for 2002.
- The PPA calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, the contract prices are not adjusted upward.

A summary of the PPA, including projected charges for the years indicated, follows:

	Vermont Yankee Contract
	(Dollars in thousands except per KWH)
Capacity acquired	106 MW
Contract period expires:	2012
Company's share of output	20%
Annual energy charge 2002 (5 months)	15,965
Estimated 2003–2015	33,352
Average cost per KWH 2002	0.052
Estimated 2003–2019	0.042

Payments totaling $0.5 million were made in 2002 to VY's non-Vermont sponsors in return for guarantees those sponsors made to Entergy to finalize the VY sale.

Although the sale closed on July 31, 2002, the Company's distribution of the sale proceeds and final accounting for the sale are pending certain regulatory approvals and the resolution of certain closing items between VY and Entergy. The Company expects its share of the Vermont Yankee power plant sale proceeds, currently estimated at between $7 million and $8 million, to be distributed in the latter part of 2003.

The sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervenor parties to the VPSB approval proceeding appealed the VPSB approval to the Vermont Supreme Court. That appeal is pending. If the appellants prevail on their appeal, the VPSB could be required to conduct additional proceedings or to reconsider its order approving the sale.

3. 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.

The Company's current purchases pursuant to the contract with Hydro-Québec entered into in December 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. There are specific step-up provisions that provide that in the event any 1987 Contract participant fails to meet its obligation under the Contract, the remaining contract participants, including the Company, will "step-up" to the defaulting participant's share on a prorated basis.

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 1987 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 Québec. The period for completing the research and development purchase was subsequently extended to March 2003.

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 2002	$11,946	$ 8,163
Estimated 2003–2015	$13,362 (1)	$ 9,131 (1)
Annual Capacity Charge 2002	$16,850	$11,514
Estimated 2003–2015	$17,122 (1)	$11,700 (1)
Average Cost per KWH 2002	$ 0.065	$ 0.065
Estimated 2003–2015	$ 0.069 (2)	$ 0.069 (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 separate arrangement established in December 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 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, 2002, Hydro-Québec had purchased or called to purchase 458,000 MWh under option B.

In 2002, Hydro-Québec exercised option A and called for deliveries to third parties at a net expense to the Company of approximately $3.0 million, including capacity charges.

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 $6.5 million, including capacity charges.

In 2000, Hydro-Québec called for deliveries to third parties at a net expense 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. 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 $27.2 million. Future estimates could change by a material amount.

The Company believes that it is probable that Hydro-Québec will call options A and B for 2003, and has purchased replacement power at a net cost of $4.7 million.

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.

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, 2002, the remaining unamortized balance of unrecovered arbitration costs is approximately $0.9 million. We believe it is probable that this balance will ultimately be recovered in rates.

4. Morgan Stanley Contract

In February 1999, the Company entered into a contract with MS. In August 2002, the MS contract was modified and extended to December 31, 2006. The contract provides the Company 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. At December 31, 2002, assets remaining include a wind power partnership investment, a note receivable from a regional hydro-power project, and 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 residual operations earned $0.02 per share in 2002, primarily as a result of an adjustment to a reserve for warranty claims. The following illustrates the results and financial statement impact of discontinued operations during and at the periods shown:

	2002	2001	2000
	(In thousands except per share)		
Revenues	$ 88	$ 156	$ 1,546
Gain (loss) on disposal	99	(182)	(6,549)
Net income (loss)	$ 99	($ 182)	($6,549)
Net income (loss) per share–basic	$ 0.02	($ 0.03)	($ 1.19)
Proceeds from asset sales	$ —	$ —	$ 6,000
Total assets	$2,619	$3,697	$ 8,411
State income taxes	$ 19	($ 175)	($1,064)
Federal income taxes	52	(550)	(3,349)
Investment tax credits	—	—	—
Income tax expense (benefit)	$ 71	($ 725)	($4,413)

M 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.

	2002 Quarter Ended				
	March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$68,866	$65,135	$73,477	$67,130	$274,608
Operating income	4,441	2,814	3,745	4,080	15,080
Net income– continuing operations	$ 3,354	$ 1,875	$ 3,042	$ 3,028	$ 11,299
Net income–discontinued operations	$ —	$ —	$ —	$ 99	$ 99
Net income applicable to common stock	$ 3,354	$ 1,875	$ 3,042	$ 3,127	$ 11,398
Basic earnings per share from:					
Continuing operations	$ 0.59	$ 0.33	$ 0.53	$ 0.57	$ 2.02
Discontinued operations	$ —	$ —	$ —	$ 0.02	$ 0.02
Basic earnings per share	$ 0.59	$ 0.33	$ 0.53	$ 0.59	$ 2.04
Weighted average common shares outstanding	5,691	5,711	5,723	5,333	5,592
Diluted earnings per share from:					
Continuing operations	$ 0.57	$ 0.32	$ 0.52	$ 0.55	$ 1.96
Discontinued operations	$ —	$ —	$ —	$ 0.02	$ 0.02
Diluted earnings per share	$ 0.57	$ 0.32	$ 0.52	$ 0.57	$ 1.98
Weighted average common and common equivalent shares outstanding	5,870	5,877	5,879	5,497	5,756

	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	4,575	4,275	4,573	3,036	16,459
Net income– continuing operations	$ 2,914	$ 2,884	$ 3,387	$ 1,675	$ 10,860
Net loss–discontinued operations	—	(150)	—	(32)	(182)
Net income 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	5,816

	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)– continuing operations	$ 3,449	($ 4,375)	$ 1,961	($ 1,340)	($ 305)
Net loss–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

Independent Auditors' Reports

**To the Board of Directors of
Green Mountain Power Corporation:**

We have audited the accompanying consolidated balance sheet of Green Mountain Power Corporation and subsidiaries (the Company) as of December 31, 2002, and the related consolidated statements of income, comprehensive income, changes in stockholders' equity and cash flows for the year then ended. The financial statements of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 and 2000 and for the years then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion which included an emphasis of matter paragraph on those financial statements in their report dated March 12, 2002. 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 audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and subsidiaries as of December 31, 2002 and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Deloitte & Touche, LLP

Boston, Massachusetts
February 7, 2003

**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

The above report of Arthur Andersen LLP is a copy of the previously issued report, and the report has not been reissued by Arthur Andersen LLP.

Consolidated Statements of Income

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

In thousands, except per share amounts	2002	2001	2000
Operating Revenues			
Residential	**$ 73,541**	$ 69,727	$ 69,832
Lease	**—**	—	—
Total residential and lease	**73,541**	69,727	69,832
Commercial and industrial–small	**76,945**	73,729	70,382
Commercial and industrial–large	**48,601**	51,638	45,729
Sales for resale	**72,312**	83,805	88,333
Other	**3,209**	4,565	3,050
Total operating revenues	**274,608**	283,464	277,326
Operating Expenses			
Power Supply			
Vermont Yankee Nuclear Power Corporation	**35,252**	30,114	34,813
Company-owned generation	**5,067**	4,742	7,777
Purchases from others	**153,129**	166,209	168,947
Other operating	**14,188**	15,924	17,644
Transmission	**15,221**	14,130	14,237
Maintenance	**8,854**	7,108	6,633
Depreciation and amortization	**14,151**	14,294	15,304
Taxes other than income	**7,623**	7,536	7,402
Income taxes	**6,043**	6,948	(691)
Total operating expenses	**259,528**	267,005	272,066
Operating income	**15,080**	16,459	5,260
Other Income			
Equity in earnings of affiliates and non-utility operations	**2,777**	2,253	2,495
Allowance for equity funds used during construction	**233**	210	284
Other income and deductions, net	**(525)**	(90)	(73)
Total other income	**2,485**	2,373	2,706
Income before interest charges	**17,565**	18,832	7,966
Interest Charges			
Long-term debt	**5,214**	6,073	6,499
Other	**1,059**	1,154	986
Allowance for borrowed funds used during construction	**(103)**	(188)	(228)
Total interest charges	**6,170**	7,039	7,257
Income (loss) before preferred dividends and discontinued operations	**11,395**	11,793	709
Dividends on preferred stock	**96**	933	1,014
Income (loss) from continuing operations	**11,299**	10,860	(305)
Net income (loss) from discontinued segment operations	**—**	—	—
Income (Loss) on disposal, including provisions for operating losses during phaseout period	**99**	(182)	(6,549)
Net Income (Loss) Applicable to Common Stock	**$ 11,398**	$ 10,678	($ 6,854)

Common Stock Data

Basic earnings (loss) per share from discontinued operations	**$ 0.02**	($ 0.03)	($ 1.19)
Basic earnings (loss) per share from continuing operations	**2.02**	1.93	(0.06)
Basic earnings (loss) per share	**$ 2.04**	$ 1.90	($ 1.25)
Diluted earnings per share from discontinued operations	**$ 0.02**	($ 0.03)	($ 1.19)
Diluted earnings per share from continuing operations	**1.96**	1.88	(0.06)
Diluted earnings per share	**$ 1.98**	$ 1.85	($ 1.25)
Cash dividends declared per share	**$ 0.60**	$ 0.55	$ 0.55
Weighted average shares outstanding–basic	**5,592**	5,630	5,491
Weighted average shares outstanding–diluted	**5,756**	5,789	5,491

1999	1998	1997	1996	1995	1994	1993	1992
$ 67,061	$ 61,697	$ 61,423	$ 60,598	$ 55,434	$ 50,966	$ 49,391	$ 45,658
—	—	—	—	—	—	419	1,883
67,061	61,697	61,423	60,598	55,434	50,966	49,810	47,541
68,004	61,816	58,700	56,530	51,245	48,374	47,310	45,552
43,518	40,201	37,841	36,704	32,616	31,381	31,569	31,775
68,305	16,529	17,847	20,667	17,541	13,521	14,441	17,258
4,160	4,061	3,512	4,510	4,708	3,955	4,123	3,114
251,048	184,304	179,323	179,009	161,544	148,197	147,253	145,240
34,987	32,910	32,817	30,596	30,222	30,300	29,785	29,230
5,582	6,412	5,327	3,330	3,786	3,113	3,150	3,804
142,699	81,706	62,222	66,320	53,915	45,777	46,066	41,878
17,582	21,291	16,780	17,615	18,120	17,296	17,353	17,239
10,800	9,389	11,122	10,833	9,874	10,374	10,775	11,103
6,728	5,190	4,785	4,463	4,210	4,465	4,352	4,692
16,187	16,059	16,359	16,280	14,116	10,683	8,572	8,065
7,295	7,242	7,205	6,982	6,428	6,277	6,125	5,902
1,242	(1,367)	7,191	6,463	5,578	5,395	6,249	6,915
243,102	178,832	163,808	162,882	146,249	133,680	132,427	128,828
7,946	5,472	15,515	16,127	15,295	14,517	14,826	16,412
2,919	2,058	285	1,564	2,131	2,287	2,239	2,305
134	104	357	175	27	263	273	186
400	(549)	789	175	94	306	19	(105)
3,453	1,613	1,431	1,914	2,252	2,856	2,531	2,386
11,399	7,085	16,946	18,041	17,547	17,373	17,357	18,798
6,716	6,991	7,274	6,872	6,546	6,868	6,539	6,542
558	1,016	691	994	1,427	867	646	479
(91)	(131)	(315)	(468)	(547)	(539)	(357)	(202)
7,183	7,876	7,650	7,398	7,426	7,196	6,828	6,819
4,216	(791)	9,296	10,643	10,121	10,177	10,529	11,979
1,155	1,296	1,433	1,010	771	794	811	831
3,061	(2,087)	7,863	9,633	9,350	9,383	9,718	11,148
(603)	(2,086)	142	1,316	1,382	825	102	(127)
(6,676)	—	—	—	—	—	—	—
($ 4,218)	($ 4,173)	$ 8,005	$ 10,949	$ 10,732	$ 10,208	$ 9,820	$ 11,021
($ 1.36)	($ 0.40)	$ 0.03	$ 0.27	$ 0.29	$ 0.18	$ 0.02	($ 0.03)
0.57	(0.40)	1.54	1.95	1.97	2.05	2.18	2.57
($ 0.79)	($ 0.80)	$ 1.57	$ 2.22	$ 2.26	$ 2.23	$ 2.20	$ 2.54
($1.36)	($ 0.40)	$ 0.03	$ 0.27	$ 0.29	$ 0.18	$ 0.02	($ 0.03)
0.57	(0.40)	1.54	1.95	1.97	2.05	2.18	2.57
($ 0.79)	($ 0.80)	$ 1.57	$ 2.22	$ 2.26	$ 2.23	$ 2.20	$ 2.54
$ 0.55	$ 0.96	$ 1.61	$ 2.12	$ 2.12	$ 2.12	$ 2.11	$ 2.08
5,361	5,243	5,112	4,933	4,747	4,588	4,457	4,345
5,361	5,243	5,112	4,933	4,747	4,588	4,457	4,345

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • At December 31

Dollars in thousands	2002	2001	2000
Assets			
Utility plant, at original cost	**$311,543**	$302,489	$291,107
Less accumulated depreciation	**122,197**	119,054	110,273
Net utility plant	**189,346**	183,435	180,834
Property under capital lease	**5,287**	5,959	6,449
Construction work in progress	**8,896**	7,464	7,389
Total utility plant, net	**203,529**	196,858	194,672
Associated companies, at equity	**14,101**	14,093	14,373
Other investments	**7,451**	6,852	6,357
Current assets	**31,432**	36,183	53,652
Deferred charges	**51,594**	72,468	46,036
Non-Utility			
Current assets	**8**	8	8
Property and equipment	**249**	250	252
Business segment held for disposal	**—**	—	—
Other assets	**738**	817	1,258
Total non-utility assets	**995**	1,075	1,518
Total assets	**$309,102**	$327,529	$316,608
Capitalization and Liabilities			
Capitalization			
Common stock equity			
Common stock	**$ 19,276**	$ 19,004	$ 18,608
Additional paid-in capital	**75,347**	74,581	73,321
Accumulated other comprehensive income	**(2,374)**	—	—
Retained earnings	**16,171**	8,070	493
Treasury stock, at cost	**(16,698)**	(378)	(378)
Total common stock equity	**91,722**	101,277	92,044
Redeemable cumulative preferred stock	**85**	12,560	12,795
Long-term debt, less current maturities	**93,000**	74,400	72,100
Total capitalization	**184,807**	188,237	176,939
Capital lease obligation	**5,287**	5,959	6,449
Current liabilities	**38,461**	38,841	68,109
Accumulated deferred income taxes	**26,471**	23,759	25,644
Unamortized investment tax credits	**3,130**	3,413	3,695
Pine Street Barge Canal site cleanup	**8,833**	10,059	11,554
Deferred credits and other	**40,172**	55,560	20,901
Non-Utility			
Current liabilities	**—**	—	—
Other liabilities	**1,941**	1,701	3,317
Total non-utility liabilities	**1,941**	1,701	3,317
Total capitalization and liabilities	**$309,102**	$327,529	$316,608

Consolidated Statements of Retained Earnings

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

Dollars in thousands	2002	2001	2000
Balance at beginning of year	**$ 8,070**	$ 493	$10,344
Net income (loss)	**11,494**	11,611	(5,840)
	19,564	12,104	4,504
Deduct cash dividends declared			
Redeemable cumulative preferred stock	**96**	933	1,014
Common stock	**3,297**	3,101	2,997
Total	**3,393**	4,034	4,011
Balance at year end	**$16,171**	$ 8,070	$ 493

1999	1998	1997	1996	1995	1994	1993	1992
$283,917	$276,853	$265,441	$248,135	$239,291	$227,991	$214,977	$201,643
102,854	94,604	87,689	81,286	75,797	69,246	64,226	58,516
181,063	182,249	177,752	166,849	163,494	158,745	150,751	143,127
7,038	7,696	8,342	9,006	9,778	10,278	11,029	11,950
4,795	5,611	10,626	13,998	8,727	6,964	9,631	9,646
192,896	195,556	196,720	189,853	181,999	175,987	171,411	164,723
14,545	15,048	15,860	15,769	16,024	16,684	16,886	17,139
6,120	5,630	6,137	4,865	4,224	4,067	5,642	4,561
33,238	35,700	29,125	30,901	30,216	28,798	26,215	28,067
43,296	35,576	35,831	43,224	42,951	35,659	33,893	19,012
48	7,974	11,654	4,490	4,131	6,295	3,656	5,016
253	1,213	10,784	11,226	11,478	11,329	11,331	10,589
9,477	—	—	—	—	—	—	—
1,321	18,127	19,622	24,211	22,259	15,792	13,639	8,111
11,099	27,314	42,060	39,927	37,868	33,416	28,626	23,716
$301,194	$314,824	$325,733	$324,539	$313,282	$294,611	$282,673	$257,218

$ 18,085	$ 17,711	$ 17,318	$ 16,790	$ 16,168	$ 15,592	$ 15,120	$ 14,712
72,594	71,914	70,720	68,226	64,206	60,378	57,178	53,510
—	—	—	—	—	—	—	—
10,344	17,508	26,717	26,916	26,412	25,727	25,229	24,801
(378)	(378)	(378)	(378)	(378)	(378)	(378)	(378)
100,645	106,755	114,377	111,554	106,408	101,319	97,149	92,645
14,435	16,085	17,735	19,310	8,930	9,135	9,385	9,575
81,800	88,500	93,200	94,900	91,134	74,967	79,800	67,644
196,880	211,340	225,312	225,764	206,472	185,421	186,334	169,864
7,038	7,696	8,342	9,006	9,778	10,278	11,029	11,950
38,150	28,825	25,286	21,037	32,629	40,441	37,925	30,099
25,201	23,389	23,501	26,726	25,292	22,082	21,001	15,504
3,978	4,260	4,542	4,825	5,107	5,390	5,672	5,955
8,815	11,220	—	—	—	—	—	—
21,132	21,020	25,680	23,417	21,642	21,962	13,541	11,805
—	720	1,119	1,752	1,124	918	666	3,524
—	6,354	11,951	12,012	11,238	8,119	6,505	8,517
—	7,074	13,070	13,764	12,362	9,037	7,171	12,041
$301,194	$314,824	$325,733	$324,539	$313,282	$294,611	$282,673	$257,218

1999	1998	1997	1996	1995	1994	1993	1992
$17,508	$26,717	$26,916	$26,412	$25,727	$25,229	$24,801	$22,806
(3,063)	(2,878)	9,438	11,959	11,503	11,002	10,631	11,852
14,445	23,839	36,354	38,371	37,230	36,231	35,432	34,658
1,155	1,295	1,433	1,010	771	794	811	831
2,946	5,035	8,204	10,445	10,047	9,710	9,392	9,026
4,101	6,331	9,637	11,455	10,818	10,504	10,203	9,857
$10,344	$17,508	$26,717	$26,916	$26,412	$25,727	$25,229	$24,801

Consolidated Statements of Cash Flows

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2002	2001	2000
		(In thousands)	
Operating Activities:			
Net Income (Loss)	**$ 11,494**	$ 11,611	($ 5,840)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**14,151**	14,294	15,304
Dividends from associated companies less equity income	**415**	280	(26)
Allowance for funds used during construction	**(335)**	(398)	(512)
Amortization of purchased power costs	**3,236**	3,767	5,575
Deferred income taxes	**2,430**	(2,167)	161
Adjustments to provision for loss on disposal of business segment	**(99)**	182	6,549
Accrued purchase power option call	**—**	(8,276)	8,276
Deferred purchased power costs	**(2,003)**	1,126	(6,692)
Rate levelization liability	**(4,483)**	8,527	—
Provision for chargeoff of deferred regulatory asset	**—**	—	3,229
Environmental proceedings and conservation expenditures	**(2,194)**	(3,380)	(2,073)
Changes in current assets and current liabilities	**4,909**	8,098	(9,628)
Other	**1,556**	1,626	(3,364)
Net cash provided by continuing operations	**29,077**	35,290	10,959
Net cash provided (used) by discontinued segment	**—**	(1,797)	245
Net cash provided by operating activities	**29,077**	33,493	11,204
Investing Activities:			
Construction expenditures	**(19,543)**	(12,963)	(13,853)
Investment in non-utility property	**(206)**	(212)	(187)
Proceeds from sale of subsidiaries	**—**	—	6,000
Investment in associated companies	**(392)**	—	—
Special fund for postretirement benefits	**—**	—	—
Net cash used in investing activities	**(20,141)**	(13,175)	(8,040)
Financing Activities:			
(Investment in) Maturity of certificate of deposit	**—**	16,173	(15,437)
Payments to acquire treasury stock	**(16,319)**	—	—
Issuance of preferred stock	**—**	—	—
Reduction in preferred stock	**(12,536)**	(235)	(1,640)
Power supply option obligation	**—**	(16,012)	15,419
Issuance of common stock	**1,037**	1,655	1,250
Short-term debt, net	**2,500**	(15,500)	7,600
Issuance of long-term debt	**42,000**	12,000	—
Reduction in long-term debt	**(25,322)**	(9,700)	(6,700)
Cash dividends	**(3,393)**	(4,034)	(4,011)
Net cash provided by (used in) financing activities	**(12,033)**	(15,653)	(3,519)
Net increase (decrease) in cash and cash equivalents	**(3,097)**	4,665	(355)
Cash and cash equivalents at beginning of year	**5,006**	341	696
Cash and Cash Equivalents at End of Year	**$ 1,909**	$ 5,006	$ 341

1999	1998	1997	1996	1995	1994	1993	1992
($3,063)	($ 2,878)	$ 9,438	$ 11,959	$ 11,503	$ 11,002	$ 10,631	$ 11,852
16,187	16,059	16,359	16,280	14,116	10,683	8,572	8,065
169	812	(90)	254	660	202	254	659
(224)	(235)	(672)	(643)	(574)	(803)	(630)	(388)
5,725	6,405	5,212	5,187	6,036	4,178	3,723	3,825
1,530	(394)	(2,997)	1,655	3,432	1,302	4,897	2,805
6,676	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—
(6,590)	(7,830)	(331)	(5,917)	(12,935)	(536)	(6,432)	(5,347)
—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—
(8,048)	1,177	(4,534)	(4,927)	(5,311)	715	(10,608)	(5,618)
4,751	(3,822)	(2,517)	781	(595)	(4,220)	1,221	(577)
(2,008)	645	6,230	1,738	(95)	2,383	(1,936)	44
15,105	9,939	26,098	26,367	16,237	24,906	9,692	15,320
(138)	—	—	—	—	—	—	—
14,967	9,939	26,098	26,367	16,237	24,906	9,692	15,320
(9,174)	(10,900)	(16,409)	(17,541)	(15,314)	(13,536)	(15,949)	(15,327)
(190)	(1,442)	218	(2,203)	(6,121)	(1,220)	(5,950)	(282)
—	11,500	—	—	—	—	—	—
—	—	—	—	—	—	—	—
—	—	—	—	—	—	(601)	(56)
(9,364)	(842)	(16,191)	(19,744)	(21,435)	(14,756)	(22,500)	(15,665)
—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—
—	—	—	12,000	—	—	—	—
(1,650)	(1,650)	(1,575)	(1,620)	(205)	(250)	(190)	(250)
—	—	—	—	—	—	—	—
1,054	1,587	3,428	4,642	4,404	3,671	4,077	3,195
900	4,384	1,600	(7,400)	(11,799)	1,198	7,402	(2,093)
—	—	—	14,000	25,917	—	20,000	17,000
(1,700)	(6,767)	(4,201)	(16,201)	(4,833)	(1,800)	(8,530)	(7,246)
(4,101)	(6,332)	(9,637)	(11,455)	(10,818)	(10,504)	(10,204)	(9,857)
(5,497)	(8,778)	(10,385)	(6,034)	2,666	(7,685)	12,555	749
106	319	(478)	589	(2,532)	2,465	(253)	404
590	271	749	160	2,692	227	480	76
$ 696	$ 590	$ 271	$ 749	$ 160	$ 2,692	$ 227	$ 480

Common Stock Data and Stock Ratios

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

		2002	2001	2000
Common Stock Data				
Net income (loss) applicable to common stock (in thousands)	($)	**11,398**	10,678	(6,854)
Shares outstanding (in thousands and net of treasury shares)				
Year-end		**4,955**	5,685	5,567
Weighted average		**5,592**	5,630	5,491
Per share of common stock				
Earnings (loss) per average share (Note 1)	($)	**2.04**	1.90	(1.25)
Dividends paid	($)	**0.60**	0.55	0.55
Payout ratio (Note 5)	(%)	**29.6**	28.9	—
Net book value	($)	**18.51**	17.81	16.53
Price range N.Y.S.E.				
High	($)	**21.08**	19.50	12-13/16
Low	($)	**15.75**	11.06	6-7/8
Year-end	($)	**20.97**	18.65	12-1/2
Price Earnings Ratio (price at year-end) (Note 5)		**10**	10	—
Capitalization (in thousands)				
Common stock equity	($)	**91,722**	101,277	92,044
Redeemable cumulative preferred stock	($)	**85**	12,560	12,795
Long-term debt (including current maturities)	($)	**101,000**	84,100	81,800
Total	($)	**192,807**	197,937	186,639
Capitalization Ratios				
Common stock equity	(%)	**47.6**	51.2	49.3
Redeemable cumulative preferred stock	(%)	**0.0**	6.3	6.9
Long-term debt (including current maturities)	(%)	**52.4**	42.5	43.8
Total	(%)	**100.0**	100.0	100.0
Other Financial Ratios				
Long-term debt weighted average annual interest rate	(%)	**7.0**	7.1	7.5
Preferred stock weighted average annual dividend rate	(%)	**4.8**	7.3	7.5
Income before interest and income taxes to long-term debt interest		**4.5**	4.2	0.1
Income before interest and after income taxes to long-term debt interest		**3.4**	3.1	0.2
Income before interest and after income taxes to total interest charges and preferred dividends		**2.8**	2.3	0.2
Operating revenues as a % of net utility property (year-end) (Note 2)	(%)	**126.2**	134.4	132.7
Operating expenses (excluding income taxes) as a % of operating revenues	(%)	**92.3**	91.7	98.4
Annual depreciation expense as a % of depreciable property	(%)	**3.2**	3.5	3.5
Accumulated depreciation as a % of depreciable property	(%)	**39.2**	39.4	37.9
Return on average common equity (Note 3)	(%)	**11.0**	11.0	(7.1)
Internally generated funds as a % of capital requirements, sinking fund obligations and other requirements (Note 4)	(%)	**67.8**	91.9	59.4
AFUDC as a % of net income (loss) applicable to common stock	(%)	**2.9**	3.7	(7.5)

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) Presented as a three-year average, net of dividend payments.
(5) Measure is not meaningful for years with net loss.

1999	1998	1997	1996	1995	1994	1993	1992
(4,218)	(4,173)	8,005	10,949	10,732	10,208	9,820	11,021
5,410	5,297	5,180	5,021	4,835	4,662	4,520	4,398
5,361	5,243	5,112	4,933	4,747	4,588	4,457	4,345
(0.79)	(0.80)	1.57	2.22	2.26	2.23	2.20	2.54
0.55	0.9625	1.61	2.12	2.12	2.12	2.11	2.08
—	—	102.5	95.5	93.8	95.1	95.9	81.9
18.60	20.15	22.08	22.22	22.01	21.73	21.49	21.07
14	20-1/16	26-1/4	29-1/8	28-5/8	31-1/4	36-5/8	33-5/8
7-1/8	10-1/16	17-5/8	22-3/4	23-7/8	23-3/8	30-3/4	29
7-7/16	10-1/2	18-3/8	23-7/8	27-3/4	27-7/8	31	33-1/8
—	—	12	11	12	13	14	13
100,645	106,755	114,377	111,554	106,408	101,319	97,149	92,645
14,435	16,085	17,735	19,310	8,930	9,135	9,385	9,575
88,500	90,200	94,900	97,934	98,967	79,800	81,600	70,130
203,580	213,040	227,012	228,798	214,305	190,254	188,134	172,350
49.4	50.1	50.4	48.8	49.7	53.3	51.6	53.7
7.1	7.6	7.8	8.4	4.2	4.8	5.0	5.6
43.5	42.3	41.8	42.8	46.1	41.9	43.4	40.7
100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
7.5	7.6	7.7	8.1	9.0	8.7	9.4	9.8
7.5	7.5	7.6	8.8	8.5	8.5	8.5	8.5
0.8	0.5	3.3	3.8	3.7	3.4	3.6	3.9
0.6	0.7	2.3	2.8	2.9	2.6	2.7	2.9
0.5	0.5	1.9	2.3	2.3	2.3	2.3	2.4
115.2	80.7	75.1	78.9	73.4	69.5	71.4	75.4
96.3	97.8	87.3	87.4	87.1	86.6	85.7	83.9
3.3	3.4	3.2	3.3	3.3	3.2	3.2	3.2
36.2	36.2	34.9	34.5	33.8	32.4	31.8	30.8
(4.0)	(3.8)	7.1	10.0	10.3	10.3	10.3	12.2
89.0	64.6	129.4	38.8	58.0	83.7	46.2	50.3
(5.3)	(5.6)	8.4	5.9	5.3	7.9	6.4	3.5

Employees, Plant Investment, Sales of Securities

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

Dollars in thousands	2002	2001	2000
Number of Active Employees full and part time, at December 31,			
—Green Mountain Power	**194**	193	197
—Subsidiaries	**0**	0	5
Utility Plant Investment (year-end)			
Intangible	**$ 12,580**	$ 14,214	$ 11,726
Steam production	**10,649**	10,609	10,525
Hydro production	**31,518**	30,581	29,728
Other production	**24,746**	21,924	21,833
Transmission	**36,846**	35,734	35,100
Distribution	**170,655**	163,930	157,959
General	**24,549**	25,496	24,236
Total utility plant investment	**311,543**	302,488	291,107
Less accumulated depreciation	**122,197**	119,053	110,273
Net utility plant	**189,346**	183,435	180,834
Property under capital lease	**5,287**	5,959	6,449
Construction work in progress	**8,896**	7,464	7,389
Total utility plant investment, net	**$203,529**	$196,858	$194,672
Beginning balance—utility plant	**$302,488**	$291,107	$283,917
Transfers to utility plant from CWIP	**17,701**	13,927	11,258
Retirements from utility plant	**(8,646)**	(2,546)	(4,068)
Ending balance—utility plant	**$311,543**	$302,488	$291,107
Beginning balance—construction work in progress	**$ 7,464**	$ 7,389	$ 4,794
Construction expenditures, net of customer advances	**19,133**	14,002	13,853
Transfers to utility plant	**(17,701)**	(13,927)	(11,258)
Ending balance—construction work in progress	**$ 8,896**	$ 7,464	$ 7,389
Sales of Securities (gross proceeds)			
Long-term debt	**$ 42,000**	$ 12,000	$ —
Common stock (excludes DRIP, ESIP, PAYSOP, restricted shares and stock grants)	**—**	—	—
Redeemable cumulative preferred stock	**—**	—	—
Total sales of securities	**$ 42,000**	$ 12,000	$ —

1999	1998	1997	1996	1995	1994	1993	1992
196	288	321	344	350	373	387	388
5	6	48	45	50	59	58	82
$ 11,276	$ 10,206	$ 9,168	$ 6,330	$ 7,451	$ 6,415	$ 4,571	$ 3,126
10,460	10,782	10,702	10,702	10,799	10,752	10,748	10,688
29,667	29,435	29,200	28,771	26,315	25,757	24,930	24,034
22,141	22,217	22,862	18,239	18,393	18,427	18,402	17,533
34,793	34,924	33,878	30,356	29,837	29,344	28,698	25,623
151,873	145,694	136,825	131,626	124,330	116,325	107,489	101,367
23,707	23,595	22,806	22,111	22,166	20,971	20,139	19,272
283,917	276,853	265,441	248,135	239,291	227,991	214,977	201,643
102,854	94,604	87,689	81,286	75,797	69,246	64,226	58,516
181,063	182,249	177,752	166,849	163,494	158,745	150,751	143,127
7,038	7,696	8,342	9,006	9,778	10,278	11,029	11,950
4,794	5,611	10,626	13,998	8,727	6,964	9,631	9,646
$192,895	$195,556	$196,720	$189,853	$181,999	$175,987	$171,411	$164,723
$276,853	$265,441	$248,135	$239,291	$227,991	$214,977	$201,643	$194,179
9,990	15,927	20,222	12,522	13,403	16,204	15,223	11,644
(2,926)	(4,515)	(2,916)	(3,678)	(2,103)	(3,190)	(1,889)	(4,180)
$283,917	$276,853	$265,441	$248,135	$239,291	$227,991	$214,977	$201,643
$ 5,611	$ 10,626	$ 13,998	$ 8,727	$ 6,964	$ 9,631	$ 9,646	$ 8,582
9,173	10,912	16,850	17,793	15,166	13,537	15,208	12,708
(9,990)	(15,927)	(20,222)	(12,522)	(13,403)	(16,204)	(15,223)	(11,644)
$ 4,794	$ 5,611	$ 10,626	$ 13,998	$ 8,727	$ 6,964	$ 9,631	$ 9,646
$ —	$ —	$ —	$ 14,000	$ 24,000	$ —	$ 20,000	$ 17,000
—	—	—	—	—	—	—	—
—	—	—	12,000	—	—	—	—
$ —	$ —	$ —	$ 26,000	$ 24,000	$ —	$ 20,000	$ 17,000

Power Supply Statistics, Electric Sales

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2002	2001	2000
Net System Capability During Peak Month (MW*)			
Total capability (MW)	**406.9**	408.0	411.1
Net system peak	**342.0**	341.2	323.5
Reserve (MW)	**64.9**	66.8	87.6
Reserve % of peak	**19.0%**	19.6%	27.1%
Net Production (MWH)**			
Hydro	**901,998**	951,146	1,053,223
Lease transmissions	**—**	—	—
Nuclear	**771,781**	736,420	803,303
Conventional steam	**2,431,115**	2,670,249	2,704,427
Internal combustion	**4,090**	18,291	35,699
Combined cycle	**81,362**	72,653	73,433
Wind	**11,458**	12,135	12,246
Total production	**4,201,804**	4,460,894	4,682,331
Less nonrequirements sales to other utilities	**2,104,172**	2,365,809	2,573,576
Production for requirements sales	**2,097,632**	2,095,085	2,108,755
Less requirements sales and lease transmissions (MWH)	**1,951,959**	1,956,232	1,954,898
Losses and Company use (MWH)	**145,673**	138,853	153,857
Losses as a % of total production	**3.47%**	3.11%	3.29%
System load factor (***)	**70.0%**	70.1%	74.2%
Sales and Lease Transmissions (MWH)**			
Residential—GMP	**553,294**	549,151	558,682
Lease MWH transmitted	**—**	—	—
Total residential	**553,294**	549,151	558,682
Commercial & industrial–small	**723,642**	718,969	704,126
Commercial & industrial–large	**661,480**	683,004	683,296
Other	**9,773**	2,030	6,713
Total retail sales and lease transmissions	**1,948,189**	1,953,154	1,952,817
Sales to Municipals & Cooperatives (Rate W)	**3,770**	3,078	2,081
Total Requirements Sales	**1,951,959**	1,956,232	1,954,898
Other Sales for Resale	**2,104,172**	2,365,809	2,573,576
Total sales and lease transmissions	**4,056,131**	4,322,041	4,528,474
Average Number of Electric Customers			
Residential	**73,861**	73,249	72,424
Commercial & industrial–small	**13,173**	12,984	12,746
Commercial & industrial–large	**21**	22	23
Other	**65**	65	65
Total	**87,120**	86,320	85,258
Average Revenue Per KWH (Cents)			
Residential including lease revenues	**12.96**	13.33	12.50
Lease charges	**—**	—	—
Total residential	**12.96**	13.33	12.50
Commercial & industrial–small	**10.35**	10.83	10.00
Commercial & industrial–large	**7.28**	7.69	6.51
Total retail including lease revenues	**10.09**	10.44	9.52
Average Use and Revenue Per Residential Customer			
KWH including lease transmissions	**7,491**	7,497	7,717
Revenues including lease revenues	**$971**	$999	$965

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

1999	1998	1997	1996	1995	1994	1993	1992
393.2	396.9	416.9	425.8	396.1	438.2	474.7	439.9
317.9	312.5	311.5	313.0	297.1	308.3	307.3	314.4
75.3	84.4	105.4	112.8	99.0	129.9	167.4	125.5
23.7%	27.0%	33.8%	36.0%	33.3%	42.1%	54.5%	39.9%
1,095,738	972,723	1,073,246	1,192,881	1,043,617	742,088	751,078	641,525
—	—	—	—	—	—	15,425	58,374
731,431	607,708	772,030	680,613	682,814	763,690	598,245	665,034
2,328,267	750,602	560,504	705,331	673,982	651,105	748,626	762,451
12,312	40,148	4,827	2,674	6,646	3,532	2,849	1,504
99,962	118,322	104,836	51,162	92,723	37,808	40,966	60,138
7,956	—	—	—	—	—	—	—
4,275,666	2,489,503	2,515,443	2,632,661	2,499,782	2,198,223	2,157,189	2,189,026
2,152,781	499,409	524,192	663,175	582,942	328,794	271,224	273,087
2,122,885	1,990,094	1,991,251	1,969,486	1,916,840	1,869,429	1,885,965	1,915,939
1,920,257	1,883,959	1,870,913	1,814,371	1,760,830	1,730,497	1,749,454	1,794,986
202,628	106,134	120,338	155,115	156,010	138,932	136,511	120,953
4.74%	4.26%	4.78%	5.89%	6.24%	6.32%	6.33%	5.53%
76.2%	72.7%	73.0%	71.6%	73.7%	69.2%	70.1%	68.5%
544,447	533,904	549,259	557,726	549,296	564,635	541,579	505,234
—	—	—	—	—	—	15,425	58,374
544,447	533,904	549,259	557,726	549,296	564,635	557,004	563,608
688,493	665,707	645,331	630,839	608,688	604,686	593,560	582,594
664,110	636,436	608,051	584,249	556,278	521,400	529,372	539,665
3,138	3,476	3,939	2,898	8,855	1,146	8,868	6,312
1,900,188	1,839,522	1,806,580	1,775,712	1,723,117	1,691,867	1,688,804	1,692,179
20,069	44,437	64,333	38,659	37,713	38,630	60,650	102,807
1,920,257	1,883,959	1,870,913	1,814,371	1,760,830	1,730,497	1,749,454	1,794,986
2,152,781	499,409	524,192	663,175	582,942	328,794	271,224	273,087
4,073,038	2,383,368	2,395,105	2,477,546	2,343,772	2,059,291	2,020,678	2,068,073
71,515	71,301	70,671	70,198	69,659	68,811	67,994	67,201
12,438	12,170	11,989	11,828	11,712	11,611	11,447	11,245
23	23	23	25	24	24	25	24
66	70	75	75	76	76	74	73
84,042	83,564	82,758	82,126	81,471	80,522	79,540	78,543
12.32	11.56	11.18	10.87	10.09	9.03	8.94	8.44
—	—	—	—	—	—	.06	.41
12.32	11.56	11.18	10.87	10.09	9.03	9.00	8.85
9.88	9.29	9.10	8.96	8.42	8.00	7.97	7.82
6.55	6.32	6.22	6.28	5.86	6.02	5.96	5.89
9.47	8.96	8.79	8.72	8.36	7.96	7.86	7.56
7,617	7,488	7,772	7,945	7,885	8,206	8,192	8,387
$938	$865	$869	$863	$796	$741	$733	$707

***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:	Donald J. Rendall, Jr. (802)655-8420 e-mail: rendall@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 2002 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 2003 (approximate)

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

Bond Ratings as of December 31, 2002 (See page 17 for details)

	Fitch	Moody's	S&P
First Mortgage Bonds	BBB+	Baa1	BBB
Preferred Stock	BBB	ba1	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

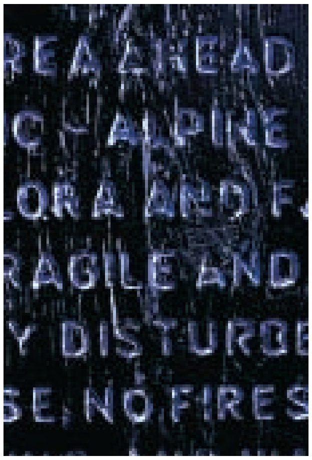
Some shareholders maintain several accounts with slight variation in the registered ownership (John A. Smith, J.A. Smith, or John A. Smith and Mary K. Smith). Even though the mailing address is identical, we are required by law to create a separate account for each name and to mail separate dividend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

2003 Annual Shareholders Meeting

All shareholders are invited to attend GMP's Annual Meeting on Thursday, May 15, 2003 at the Elley-Long Music Center at St. Michael's College, 223 Ethan Allen Drive, Colchester Vermont. The meeting will begin at 10 a.m.



Built by the Green Mountain Club between 1910 and 1930, the Long Trail is the oldest long-distance trail in the United States. The Long Trail follows the main ridge of the Green Mountains from the Massachusetts-Vermont line to the Canadian border as it crosses Vermont's highest peaks. It was the inspiration for the Appalachian Trail, which coincides with it for one hundred miles in the southern third of the state.

The Green Mountain Club, a private nonprofit organization with 9,000 members, continues to maintain and protect the Long Trail system. Green Mountain Power has been a supporter of the Green Mountain Club, including the volunteer workday last September, which provided the inspiration for the opening paragraph of our annual letter to shareholders. For more information about the Long Trail and the Green Mountain Club, go to **www.greenmountainclub.org**.

Photographs on cover and at left by Alden Pellett.

GREEN MOUNTAIN POWER

163 Acorn Lane
Colchester, Vermont 05446

www.greenmountainpower.biz