CVPS 2002:
Defined by Achievement

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Central Vermont Public Service
ANNUAL REPORT 2002

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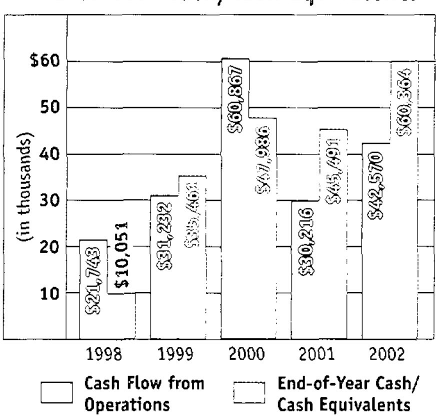
service we provide. We refer to these performance standards as SERVE — Serving Everyone with Reliability, Value and Excellence.

Jointly developed with regulators to measure everything from meter reading, to outage duration, to employee safety, I believe our standards are among the toughest, most comprehensive in the nation. The results, as reported to the Vermont Public Service Board, are impressive. The company met or exceeded 14 of 17 standards for the year.

For example, one goal is to answer 75 percent of customer calls within 20 seconds. In 2002, our Customer Information Center employees answered more than 233,000 calls, more than 95 percent of them within 20 seconds. Overall, 89 percent of customers surveyed following customer-initiated contact with the company said they were satisfied — compared to the standard of 82 percent.

Cash Flow from Operations and End-of-Year Cash/Cash Equivalents



We also make several service guarantees to our customers, and provide a $10 credit if we don't meet expectations. We guarantee customer-requested work will be done when promised, for example.

While we are pleased with our guaranteed performance and SERVE results, we continue to work to improve our quality on every standard, and use them daily as catalysts to deliver ever-higher service to customers.

CVPS Embraces Sarbanes-Oxley Rules

Not every company is so committed to its customers and shareholders. Due to serious misconduct at a variety of companies, President Bush signed the Sarbanes-Oxley Act into law last July. The law prompted fundamental changes in the way many public companies do business. Fortunately, many of the law's requirements, such as having a truly independent board of directors, were already standard practice here at CVPS. We have also enhanced senior management's responsibility for financial reporting and made other corporate governance changes to ensure our full compliance with the law.

At the same time, we recognize that a foundation of trust and credibility is built on sound values, not legal prescriptions. CVPS will continue in its commitment to doing what is right — not because the law requires it, but because that's how we do business.

Looking forward to 2003

Each of our 2002 achievements deserves considerable recognition. Collectively, they provide irrefutable evidence of our employees' extraordinary capabilities and the company's resolve to make good on our commitments and accomplish long-term goals.

Still, challenges and opportunities remain for 2003. We must continue to creatively and aggressively manage our power supply to reduce costs and lower risks. We must continue to focus on the Right Way to Work to further improve our productivity while reducing costs. We must build on our early successes to meet and exceed every SERVE standard for customer service. And we must continue to advance Catamount's strategy for shareholder growth.

In short, we must do everything within our power to earn the continuing confidence of our customers, investors and employees. As one of your employees, I remain committed to doing so, and look forward to reporting to you next year on our achievements in 2003.

Sincerely,

Robert H. Young

Robert H. Young
President and Chief Executive Officer

The sale also produced substantial value for customers and shareholders by eliminating the risks to CVPS from the plant's continued operation and decommissioning. Entergy will now pay for unexpected operating costs, to maintain the plant during unscheduled plant outages, and any increase in decommissioning costs.

The magnitude of this once-in-a-lifetime transaction triggered an exhaustive review rivaling any regulatory proceeding in state history. Thanks in part to the work of scores of determined CVPS employees, the end result is an historic step forward for CVPS and Vermont.

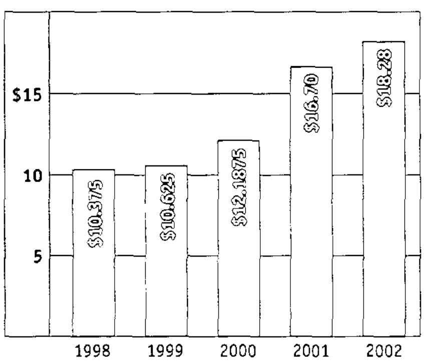
CVPS employees produced over $2 million in operational savings in 2002, the first full year of using the Right Way To Work.

IPP Settlement Lowers Power Costs

The Vermont Public Service Board in January 2003 approved a hard-won settlement between CVPS, 13 municipal utilities and Vermont's independent power producers to lower IPP costs. The settlement will reduce power costs for all Vermont utilities over the next 10 years through a direct IPP revenue reduction and elimination or reduction of unnecessary IPP financial security requirements.

The settlement parties also agreed to support legislation, since passed, that authorized the use of securitization, a low-cost financing mechanism to buy down IPP contracts. That could produce millions of dollars in additional savings. The negotiations were difficult and time-consuming, but our customers and the company will benefit from their successful conclusion.

Stock Price



Subsidiary Sale Resolves Costly Litigation

CVPS also negotiated a positive resolution to a series of complex, time-consuming legal issues related to our New Hampshire subsidiary, Connecticut Valley Electric Company.

To successfully defend the collection of prudently incurred costs in New Hampshire, CVPS and CVEC pursued litigation that ultimately rose to the U.S. Supreme Court. While working to preserve our constitutional rights through the legal system, myriad issues related to power supply, cost recovery and municipalization continued to consume our financial and human resources, with no end in sight.

Through the proposed book-value sale of our CVEC franchise and electric system to Public Service Company of New Hampshire, we will settle those issues and receive $21 million in stranded power costs. The Federal Energy Regulatory Commission, New Hampshire Public Utility Commission, and possibly the Securities and Exchange Commission, must approve the sale, which is expected to close by Jan. 1, 2004.

Company-Wide Focus on Cost Reduction

CVPS employees produced more than $2 million in operational savings in 2002, the first full year of using the Right Way to Work, a systematic continuous improvement process designed to root out unnecessary costs and improve service. The RWTW places responsibility on every employee and provides each with the simple but powerful statistical analysis tools necessary to succeed.

While we continue to see double-digit increases in health care costs and property taxes, RWTW projects have already identified an expected $3 million in operational savings for 2003. With dozens of additional projects under way, I am confident that we will realize even greater results. This is critical to our dual goals of avoiding the need to increase rates while continuing to create value for shareholders.

CVPS met or exceeded 14 of 17 customer-work performance standards that are among the toughest, most comprehensive in the nation.

Tough Performance Standards, Guarantees, Improve Service

While operational efficiency is important to our success, service to our customers is equally critical. CVPS measures work performance against 17 standards to test the quality of every major

To Our Shareholders:

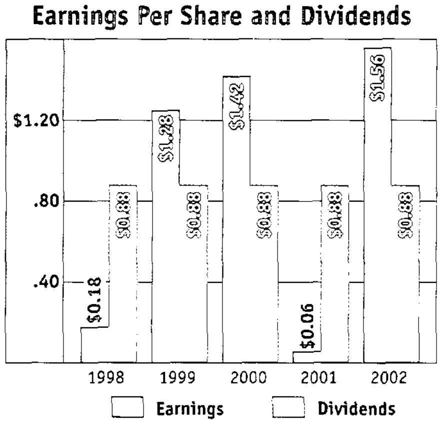
It is with pleasure that I report on the challenges, hard work and successes of the past year. We made tremendous progress in 2002. Longstanding issues were resolved. Immediate challenges were confronted and met. Necessary actions for future growth were identified and implementation work began.

The results — measurable, impressive and unmistakable — improved the company's financial posture and were reflected by continued market confidence. The company reported net income of $19.8 million in 2002, or $1.56 per basic share and $1.53 per diluted share of common stock, compared to 2001 net income of $2.4 million, or $.06 per basic and diluted share of common stock. Cash and cash equivalents totaled $60.4 million on Dec. 31, up $14.9 million for the year.

CVPS also posted strong gains in stock price despite a tumultuous market, beginning 2002 at $16.89 per share and closing at $18.28 per share, a gain of 7.6 percent. By comparison, the S&P 500 Index fell 25 percent and the Dow Jones Utility Index fell 26 percent in 2002. Rating agencies Fitch and Standard & Poor's reaffirmed the company's investment-grade credit ratings, and for the second straight year awarded CVPS a stable outlook.

CVPS's wholly owned subsidiary, Catamount Energy Corporation, also continued to improve its financial footing, as it builds a premier wind energy company. Catamount's after-tax earnings were $1.5 million in 2002, compared to losses of $8.7 million in 2001.

Earnings Per Share and Dividends



Catamount made substantial progress in rebalancing its portfolio toward growth and profitably in the wind sector with the sale of its Gauley River Project, Heartlands gas power plant interest, and an agreement to sell its investments in the Fibrothetford facility. The Fibrothetford sale is expected to close early in 2003. Sale proceeds will be used to lower debt.

Catamount now owns interests in two wind farms in Germany, has several projects at various stages of development in the United States, and has developed a solid list of potential opportunities. With partner Force 9 Energy Ltd., Catamount has also begun the early stages of development on six projects in Scotland and England. As a conservatively financed subsidiary, Catamount is now positioned to create long-term value for our shareholders by producing clean, renewable wind energy.

Our Vital Few Goals Produce Results

CVPS's and Catamount's financial revitalization are the result of the hard work of focused, creative employees linked through a shared set of 2002 work priorities, known as the Vital Few. They are: create shareholder value; reduce power and transmission costs and risks; engage employees in the Right Way to Work; eliminate the need to seek a rate increase until at least 2006; and exceed the company's customer-service quality standards. These five critical goals created a common unity of overarching purpose and a high-level focus on every operational task we perform, serving shareholders and customers alike.

Our goals are straightforward, demanding and ultimately rewarding. The Vital Few concentrated the creative energy of our entire workforce to fuel the achievements that defined CVPS in 2002, including settlement of a host of major issues that have weighed on the company for several years.

Vermont Yankee Sale Cuts Costs and Risks

CVPS successfully delivered on the single largest possible action to reduce costs and risks by securing the sale of Vermont Yankee Nuclear Power Station to Entergy for $180 million on July 31. The sale will produce at least $82 million in power cost savings through a purchased power contract with the plant through 2012.

> The 2002 results — measurable, impressive and unmistakable — were reflected by continued market confidence.

The contract protects customers from wild upward swings in the wholesale market, but also includes a one-way price adjuster that lowers the power price if market prices drop. Overall, our VY costs are expected to be 25 percent lower than if we continued to operate the plant ourselves.

Central Vermont Public Service Corporation

JEAN GIBSON
Senior Vice President
Chief Financial Officer
and Treasurer

March 28, 2003

CORRECTION TO CENTRAL VERMONT PUBLIC SERVICE CORPORATION ANNUAL REPORT 2002

Dear Shareholders:

The Company has filed an amended Form 10-K with the Securities and Exchange Commission ("SEC") on March 28, 2003 for the year ended December 31, 2002 to correct the statements in the third paragraph of Mr. Young's letter and on page 8 of the Annual Report. The statements made indicates that both Standard and Poor's and Fitch IBCA reaffirmed the Company's credit ratings in 2002. In fact, only Standard and Poor's reaffirmed the Company's credit ratings in 2002.

Investors and others who are interested are encouraged to review Central Vermont Public Service Corporation's SEC filings by clicking on the "Investor Relations" button located on the Company's web site at www.cvps.com.

Sincerely,

Jean H. Gibson

Jean H. Gibson
Senior Vice President,
Chief Financial Officer, and Treasurer

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Management's Discussion and Analysis of Financial Condition and Results of Operations

FORWARD-LOOKING STATEMENTS

Statements contained in this report that are not historical fact, including Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements intended to qualify for the safe-harbors from liability established by the Private Securities Reform Act of 1995. Statements made that are not historical facts are forward-looking and, accordingly, involve estimates, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Actual results will depend, among other things, upon actions of regulators and legislators, pending sale of the Company's wholly owned subsidiary Connecticut Valley Electric Company ("Connecticut Valley"), performance of the Vermont Yankee nuclear power plant, weather conditions, and performance of the Company's non-regulated businesses. The Company cannot predict the outcome of any of these matters.

CRITICAL ACCOUNTING POLICIES

Preparation of the Company's financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") requires Management to make estimates and assumptions that affect reported amounts of assets and liabilities, the disclosures of contingent assets and liabilities, and revenues and expenses. Note 1 to the Consolidated Financial Statements is a summary of significant accounting policies used in preparation of the Company's financial statements. The following is a discussion of the most critical accounting policies used by the Company.

Regulation The Company is subject to regulation by the Vermont Public Service Board ("PSB"), the New Hampshire Public Utilities Commission ("NHPUC") and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting and other matters pertaining to regulated operations. As such, the Company currently prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), for its regulated Vermont service territory, FERC-regulated wholesale businesses and Connecticut Valley's New Hampshire service territory. In order for a company to report under SFAS No. 71, the company's rates must be designed to recover its costs of providing service and the company must be able to collect those rates from customers. If rate recovery becomes unlikely or uncertain, whether due to competition or regulatory action, this accounting standard would no longer apply to the Company's regulated operations. In the event the Company determines that it no longer meets the criteria for applying SFAS No. 71, the accounting impact would be an extraordinary non-cash charge to operations of approximately $45.7 million on a pre-tax basis as of December 31, 2002, assuming that no stranded cost recovery would be allowed through a rate mechanism. Criteria that could give rise to the discontinuance of SFAS No. 71 include 1) increasing competition that restricts the Company's ability to establish prices to recover specific costs and 2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. Management periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, Management believes future recovery of its regulatory assets in the State of Vermont and the State of New Hampshire for the Company's retail and wholesale businesses is probable.

Valuation of Long-Lived Assets The Company periodically evaluates the carrying value of long-lived assets and long-lived assets to be disposed of, including its investments in nuclear generating companies, its unregulated investments, and its interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. See Note 3 to the Consolidated Financial Statements for further discussion of impairment of non-utility investments.

Utility Plant and Maintenance Utility plant is recorded at cost. The cost of additions, including betterments and replacements of units of property, is charged to utility plant. Based on regulatory accounting, maintenance and repairs, including the cost of removing minor items of property, are expensed as incurred. The cost of units of property replaced or retired, plus removal or disposal costs, less salvage, is charged to accumulated depreciation. The Company capitalizes direct costs and certain indirect costs, including the cost of debt and equity capital associated with construction and retirement activity, as prescribed by GAAP and in accordance with regulatory practices.

Depreciation The Company has a significant investment in electric plant. Depreciable assets related to generation, transmission, distribution and general functions represent approximately 95 percent of total depreciation. The Company depreciates these assets utilizing a composite rate, which currently includes a component for net negative salvage. The Company uses a straight-line basis over the useful life of the related assets, which corresponds with the anticipated physical lives of these assets in most cases. In order to substantiate the remaining physical lives of the investment in electric plant, outside consultants are engaged to perform depreciation studies on that property. The most recent depreciation study was completed and implemented in the second quarter of 2002. As prescribed by GAAP and regulatory practices, adjustments to the estimated depreciable lives of electric plant are recorded on a prospective basis.

Purchased Power The Company records the annual cost of power obtained under long-term contracts as operating expenses. Since these contracts do not convey to the Company the right to use the related property, plant or equipment, they are considered executory in nature.

Revenues Revenues related to the sale of electricity are generally recorded when service is rendered or when electricity is distributed to customers. Electricity sales to individual customers are based on the monthly reading of their meters. Estimated unbilled revenues are recorded at the end of each monthly accounting period. The Company follows the accrual method of accounting for revenues, recognizing revenue for kilowatt-hours that have been delivered but not yet billed through the end of the monthly accounting period. The determination of unbilled revenues requires the Company to make various estimates including 1) energy generated, purchased and resold, 2) losses of energy over transmission and distribution lines, 3) kilowatt-hour usage by retail customer mix-residential, commercial and industrial, and 4) average retail customer pricing rates. Unbilled revenues as of December 31, 2002, 2001 and 2000 were $16 million, $16.4 million and $17.1 million, respectively.

Pension and Postretirement Benefits The Company records pension and other postretirement benefit costs in accordance with SFAS No. 87, *Employers' Accounting for Pensions*, and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*. Under these accounting standards, assumptions are made regarding the valuation of benefit obligations and performance of plan assets. Delayed recognition of differences between actual results and those assumed is a required principle of these standards. This approach allows for systematic recognition of changes in benefit obligations and plan performance over the working lives of the employees who benefit under the plans. The following is a list of the primary assumptions, which are reviewed annually for the September 30 measurement date.

- **Discount Rate** – The discount rate is used to record the value of benefits, which are based on future projections, in terms of today's dollars. As of September 30, 2002, the discount rate was decreased from 7.25 percent to 6.5 percent.
- **Expected Return on Plan Assets ("ROA")** – The Company projects the future ROA based principally on prior performance and receives guidance from the Company's actuaries. The projected future value of assets

reduces the benefit obligation a company will record. As of September 30, 2002, the ROA was reduced from 8.5 percent to 8.25 percent.

- **Rate of Compensation Increase** – The Company projects employees' annual pay increases, which are used to project employees' pension benefits at retirement. As of September 30, 2002, the rate of compensation increase was changed from 4.5 percent to 4 percent.
- **Health Care Cost Trend** – The Company projects expected increases in the cost of health care. For measurement purposes, a 10 percent and 9.5 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2003, for pre-65 and post-65 claims costs, respectively.
- **Amortization of Gains/(Losses)** – The Company can select the method by which gains or losses are recognized in financial results. These gains or losses are created when actual results differ from estimated results based on the above assumptions. The Company recognizes these gains and losses ratably over a five-year period.

A variance in the discount rate, expected return on plan assets, rate of compensation increase or amortization method could have a significant impact on the pension costs recorded under SFAS No. 87. A variance in health care cost trend assumptions could have a significant impact on costs recorded under SFAS No. 106 for postretirement medical expense. The impact of a one-percentage-point increase or decrease in the assumed health care cost trend as calculated by the Company's actuaries is $1.2 million and ($1.1 million), respectively, as of December 31, 2002. The market value of pension plan assets has been affected by sharp declines in the capital markets. As a result, the Company anticipates increases in pension expense for 2003 of $1.7 million; pension cost and cash funding requirements are expected to increase in future years and could become even more material without a substantial recovery in the capital markets. See Note 10 to the Consolidated Financial Statements.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), the Company recognizes tax assets and liabilities 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 ratably to income over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized. See Note 11 to the Consolidated Financial Statements.

RESULTS OF OPERATIONS

Earnings Overview The Company's 2002 net income was $19.8 million, or $1.56 per basic and $1.53 per diluted share of common stock, which equates to a 9.6 percent consolidated return on average common equity. This compares to 2001 net income of $2.4 million, or $.06 per basic and diluted share of common stock, and 2000 net income of $18 million, or $1.42 per basic and $1.41 per diluted share of common stock. The consolidated return on average common equity was 0.4 percent for 2001 and 8.6 percent for 2000.

2002 vs. 2001: Excluding all nonrecurring items, the Company's net income for 2002 compared to 2001 is as follows:

	Dollars in Millions			EPS		
	2002	2001	Change	2002	2001	Change
Net Income – as reported	**$19.8**	$2.4	$17.4	**$1.56**	$.06	$1.50
Vermont Yankee sale – tax benefits	**(2.5)**	-	(2.5)	**(.22)**	-	(.22)
Rate case settlement – regulatory asset write-off	**-**	5.3	(5.3)	**-**	.46	(.46)
Rate case settlement – Hydro-Quebec power costs	**-**	(1.7)	1.7	**-**	(.15)	.15
Catamount – asset impairment charges	**2.1**	9.8	(7.7)	**.18**	.85	(.67)
Eversant – investment write-down	**-**	1.1	(1.1)	**-**	.10	(.10)
Connecticut Valley – extraordinary charge	**-**	0.2	(0.2)	**-**	.02	(.02)
Subtotal nonrecurring items	**(0.4)**	14.7	(15.1)	**(.04)**	1.28	(1.32)
Net Income – excluding nonrecurring items	**$19.4**	$17.1	$2.3	**$1.52**	$1.34	$0.18

Excluding the above nonrecurring items, factors that contributed to the $2.3 million increase in earnings include: 1) higher retail sales revenue and other operating revenue of $5.1 million after-tax, or $.43 per share, resulting from higher average retail rates due to a 3.95 percent retail rate increase beginning July 1, 2001, an increase in retail mWh sales of approximately 1 percent and the sale of non-firm transmission under the Company's open access transmission tariff; 2) lower losses at Eversant of $0.5 million, or $.04 per share, primarily related to the 2002 settlement of an IRS audit resulting in a reversal of a related interest expense accrual previously recorded in the fourth quarter of 2001; and 3) higher earnings at Catamount of $2.5 million, or $.21 per share, primarily due to higher equity in earnings in 2002 from several of its investments and realized development revenue upon the sale of one of its investments in the fourth quarter of 2002. See Note 3 to the Consolidated Financial Statements for more detail related to Catamount's investments and the after-tax impairment charges included in the table.

Offsetting the favorable impacts to 2002 earnings were, 1) higher net power costs of $3.4 million after-tax, or $.29 per share, primarily related to a 2001 reversal of a December 2000 accrual for estimated costs for installed capacity deficiency charges in ISO-New England with no similar reversal in 2002 and lower ISO-New England market prices for resale sales; and 2) higher operating and other costs of $2.4 million after-tax, or $.21 per share of common stock, primarily related to a $0.6 million, or $.05 per share, one-time payment related to closing the Vermont Yankee sale, higher net transmission costs of $0.4 million, or $.04 per share, higher property tax expense of $0.4 million, or $.04 per share, an increase in bad debt reserves of $0.7 million, or $.06 per share, due to several announced bankruptcies, lower interest and dividend income of $0.7 million, or $.06 per share, a 2001 settlement of $0.3 million, or $.03 per share, related to Wyman generating station with no similar item in 2002, higher other operating expenses of $0.2 million, or $.02 per share, offset by a $1 million, or $.09 per share, reversal of certain environmental reserves.

The Company's June 26, 2001 rate case settlement allows for an 11.0 percent rate of return on common equity for the Vermont utility. In 2002, the Company's Vermont utility earned approximately $0.4 million, on an after-tax basis, above its allowed rate of return. In accordance with its rate case settlement, the Company reduced the Vermont utility's earnings by that amount to satisfy its earnings cap requirement. The related deferral of approximately $0.7 million pre-tax is included in Other deferred credits on the Company's Consolidated Balance Sheet. The Company and Vermont Department of Public Service ("DPS") are currently in discussions as to the balance sheet classification so as to preserve ratepayer benefit as required by the rate case settlement.

2001 vs. 2000: Excluding all nonrecurring items, the Company's net income for 2001 compared to 2000 is as follows:

	Dollars in Millions			EPS		
	2001	2000	Change	2001	2000	Change
Net Income - as reported	$2.4	$18.0	$(15.6)	$.06	$1.42	$(1.36)
Rate case settlement - regulatory asset write-off	5.3	-	5.3	.46	-	.46
Rate case settlement - Hydro-Quebec power costs	(1.7)	-	(1.7)	(.15)	-	(.15)
Catamount - asset impairment charge	9.8	0.6	9.2	.85	.05	.80
Eversant - investment write-down	1.1	-	1.1	.10	-	.10
Connecticut Valley - extraordinary charge	0.2	-	0.2	.02	-	.02
Millstone Unit # 3 settlement	-	(3.2)	3.2	-	(.28)	.28
Connecticut Valley - favorable court decision	-	(1.7)	1.7	-	(.14)	.14
Subtotal nonrecurring items	14.7	(4.3)	19.0	1.28	(.37)	1.65
Net Income - excluding nonrecurring items	$17.1	$13.7	$3.4	$1.34	$1.05	$0.29

Excluding the above nonrecurring items, factors that contributed to the $3.4 million increase in earnings include 1) higher retail sales revenue of $1.4 million after-tax, or $.12 per share, resulting from higher average retail rates due to the June 26, 2001 approved rate order, offset by a 1.9 percent decrease in retail mWh sales; 2) lower other utility revenues of $0.7 million after-tax, or $.06 per share, primarily due to a FERC-ordered refund of transmission costs in the fourth quarter of 2000; 3) lower net power costs of $4.2 million after-tax, or $.37 per share, mostly related to lower Vermont Yankee operating and decommissioning costs; 4) higher operating and other costs of $2.9 million after-tax, or $.25 per share, due to higher service restoration costs related to storm activity in the first quarter of 2001 and higher costs related to employee benefits; 5) lower net losses at Eversant of $1.3 million, or $.12 per share, related to Eversant's investment in HSS, offset by higher business development costs and a fourth quarter 2001 accrual for a potential income tax liability; and 6) lower earnings at Catamount of $0.2 million, or $.01 per share.

Operating Revenues and Megawatt-hour ("mWh") Sales Revenues from operations and related mWh sales for 2002, 2001 and 2000 are summarized below:

	mWh Sales			Revenues (000's)		
	2002	2001	2000	**2002**	2001	2000
Retail sales:						
Residential	**971,941**	952,509	963,615	**$129,692**	$124,844	$124,237
Commercial	**937,919**	933,928	933,851	**112,547**	110,482	106,089
Industrial	**428,238**	431,371	465,418	**36,076**	35,888	38,521
Other retail	**6,239**	6,291	6,280	**1,795**	1,787	1,779
Total retail sales	**2,344,337**	2,324,099	2,369,164	**280,110**	273,001	270,626
Resale sales:						
Firm (1)	**2,392**	1,927	2,830	**137**	139	142
Entitlement (2)	-	165,184	299,326	-	7,303	10,763
Alliance (3)	-	-	611,225	-	-	22,192
Other	**442,187**	406,694	573,055	**15,806**	16,153	20,534
Total resale sales	**444,579**	573,805	1,486,436	**15,943**	23,595	53,631
Other revenues	-	-	-	**7,336**	5,880	9,669
Total	**2,788,916**	2,897,904	3,855,600	**$303,389**	$302,476	$333,926

(1) Firm sales are compensatory and are based on FERC filed tariffs.
(2) Entitlement sales are transfers of the Company's entitlement, in a plant or generating facility, in which it has a firm entitlement in, such as Vermont Yankee and Hydro-Quebec. In 2001 and 2000 the Company transferred or sold specific MW entitlements of its share of the Vermont Yankee plant including plant output and related capacity costs.
(3) Alliance sales are related to an alliance with Virginia Power that supplied wholesale power primarily in the Northeast states. In the third quarter of 1999 the Company and Virginia Power agreed to discontinue the Alliance and related transactions ended in 2000.

The table below summarizes the components of increases or decreases in revenues compared to the prior year (dollars in thousands):

	2002	2001
Revenue increase (decrease) from:		
Retail mWh sales	**$2,745**	$(4,239)
Retail rates (unit price)	**4,364**	6,614
Changes in firm resale sales	**(2)**	(3)
Changes in entitlement sales	**(7,303)**	(3,460)
Change in Alliance sales	**-**	(22,192)
Changes in other resale sales	**(347)**	(4,381)
Changes in other revenues	**1,456**	(3,789)
Net increase (decrease) over prior year	**$913**	$(31,450)

2002 vs. 2001: Operating revenues increased $0.9 million as a result of the following factors:

- Retail sales increase of $7.1 million resulting from higher average retail rates due to a 3.95 percent retail rate increase beginning July 1, 2001, and a 0.9 percent increase in mWh sales.
- Entitlement sales decrease of $7.3 million due to the completion of a five-year power contract that ended in October 2001.
- Other resale sales decrease of $0.3 million primarily due to lower ISO-New England market prices, offset by an 8.7 percent increase in mWh sales for the same period. The increased mWh sales are attributed to the end of the Vermont Yankee entitlement sale described below and an 11.8 percent increase in the Company's share of Vermont Yankee output beginning March 2, 2002, as a result of the early return of Vermont Yankee entitlements from the secondary purchasers. The additional output that the Company receives from the Vermont Yankee plant is either used to support own-load needs or sold in the short-term market mostly to ISO-New England. Although the Vermont Yankee plant was sold in July 2002, the Company receives approximately 35 percent of the plant output through a purchased power agreement. See Power Supply Matters for more information regarding the Vermont Yankee sale.
- Other revenues increase of $1.5 million primarily due to the sale of non-firm transmission under the Company's open access transmission tariff.

2001 vs. 2000: Operating revenues decreased approximately $31.5 million as a result of the following factors:

- Retail sales increased $2.4 million due to the favorable impact of a 3.95 percent increase in retail rates beginning July 1, 2001, which contributed approximately $4.9 million, and the favorable impact of customer mix and unit pricing, which contributed $1.7 million. Offsetting these favorable impacts was a 1.9 percent decrease in mWh sales resulting in a $4.2 million reduction in retail sales revenue.
- Entitlement sales decreased $3.5 million due in part to a five-year power contract in which the Company sold approximately 15 percent of its share of Vermont Yankee output at full cost; the contract ended in October 2001. Additionally, in 2000 and 2001, the Company entered into short-term transactions in which it sold energy from Vermont Yankee based on a portion of its MW entitlement, and in return purchased energy from other nuclear plants based on the same MW. Offsetting purchases are included in the Purchased Power and Produced Energy (mWh) table below. In 2001, the sale part of the transactions of approximately $1.1 million was included in Other sales, while in 2000 the sale part of the transactions of approximately $2.2 million was included in Entitlement sales.
- Alliance sales decreased $22.2 million due to termination of an alliance with Virginia Power.
- Other resale sales decreased $4.4 million due to lower output and purchases from the Company's power resources, which affected the amount of energy available for resale. Those reductions included the Vermont Yankee and Millstone Unit #3 refueling outages in 2001, lower Hydro-Quebec Firm Energy Contract purchases due to phase-out of the contract, and lower hydro production from the Company's owned facilities and fewer hydro purchases due to low rainfall. Offsetting this decrease were Vermont Yankee unit swap transactions, which were included in Other in 2001 and Entitlement in 2000.
- Other revenues decreased $3.8 million compared to 2000 primarily due to nonrecurring income in 2000 with no comparable items in 2001. In 2000, Other revenues included nonrecurring income of $2.6 million for the reversal of the provision for rate refunds due to a favorable First Circuit Court of Appeals decision allowing Connecticut Valley to recover all of its power costs in rates and a $0.8 million FERC-ordered refund of transmission costs from Citizens Utilities.

Net Purchased Power and Production Fuel Costs The Company discusses in more detail its power supply sources, purchased power commitments and liabilities regarding nuclear investments in Power Supply Matters below. The cost components of net purchased power and production fuel for 2002, 2001 and 2000 are summarized in the following table (dollars in thousands):

	2002		2001		2000	
	Units	**Amount**	Units	Amount	Units	Amount
Purchased power						
Capacity (MW)	**435**	**$69,572**	436	$86,164	427	$96,850
Energy (mWh)	**2,627,117**	**77,193**	2,784,443	61,498	3,594,942	89,090
Total purchased power		**146,765**		147,662		185,940
Production fuel (mWh)	**378,232**	**2,732**	320,022	2,995	452,387	4,825
Total purchased power and production fuel		**149,497**		150,657		190,765
Less entitlement and other resale sales (mWh)	**442,187**	**15,806**	571,878	23,456	1,483,607	53,489
Net purchased power and production fuel costs		**$133,691**		$127,201		$137,276

2002 vs. 2001: The sale of Vermont Yankee effective July 31, 2002, resulted in a significant change to the Company's purchased power cost structure when comparing 2002 with 2001. While the Company continues to purchase a similar share of plant output, all payments are made on an energy (mWh) basis under a purchased power agreement ("PPA") that became effective after the sale. Because of high PPA prices in 2002, costs were significantly higher compared to continued ownership of the plant. In anticipation of these increased costs the Company sought and the Vermont Public Service Board ("PSB") approved an Accounting Order that authorized the Company to defer incremental cost increases in 2002 resulting from the sale. In 2002 Vermont Yankee purchases had a favorable impact on energy and capacity costs of approximately $1.8 million compared to an unfavorable impact of approximately $3.4 million if not for the Accounting Order. The following is a summary of factors that impacted Vermont Yankee costs in 2002 compared to 2001.

- The Company is no longer responsible for the plant's capacity costs and all purchases under the PPA are recorded as energy purchases. Prior to the sale, the great majority of Vermont Yankee costs were recorded as capacity costs.
- In March 2002, as a result of negotiations with secondary purchasers, the Company's entitlement share of output from the plant increased by 11.8 percent. These additional purchases resulted in a $2.2 million and $3.2 million increase in capacity and energy costs, respectively, while supplying an additional 118,000 mWh to the Company.
- The Company deferred approximately $5.2 million in energy costs based on the approved Accounting Order resulting in a mitigation of $5.2 million in energy costs.
- The favorable impact of a $1.3 million reduction of purchased power expense due to state tax benefits available to Vermont Yankee, resulting in a $1.3 million decrease in capacity costs.

Overall, the $6.5 million increase in net purchased power and production fuel costs resulted from the following factors:

- Lower market prices for energy throughout much of 2002 reduced revenue used to offset the cost of power, resulting in $3.2 million of additional net costs.
- Power requirements related to increased retail sales, losses, and capacity needs added $1.1 million.
- Lower net Vermont Yankee costs of approximately $1.8 million as explained above.
- A $5.4 million unfavorable impact resulting from items in 2001 with no comparable items in 2002, which are explain in more detail below.

2001 vs. 2000: Capacity costs decreased $10.7 million due to favorable items in 2001 including the June 26, 2001 rate order, which ended the Hydro-Quebec power cost disallowances, resulting in a $2.9 million reversal of a second-quarter 2001 accrual for under-recovery of power costs, and a $2.5 million reversal of a December 2000 accrual for estimated costs for installed capacity in ISO-New England due to the resolution of a December 2000 FERC Order. Additionally, Vermont Yankee capacity costs were lower by $3.8 million, net of deferrals for refueling outage costs, due to lower decommissioning costs beginning July 1, 2001, and lower interest costs and operational efficiencies at the plant.

- Energy costs decreased $27.6 million primarily due to Alliance-related purchases in 2000 of approximately $22 million, which were offset by Alliance resale sales. Other factors included decreased output by expensive IPP hydro units, decreased balancing purchases from ISO-New England, and a net deferral related to incremental costs of replacement power during nuclear refueling outages.
- Production fuel costs decreased $1.8 million primarily due to lower output and costs related to the McNeil generating plant, which was operated at a higher capacity level in 2000 to support reliability, and lower output from the Wyman generating station.
- Entitlement and other resale sales decreased approximately $30 million primarily related to the Alliance-related sales and other factors as explained in Operating Revenues above.

Other Operating Costs Other major elements of the Consolidated Statement of Income are discussed below.

Maintenance expenses There was no significant variance in maintenance expenses in 2002 compared to 2001. The $3.4 million increase in 2001 compared to 2000 is primarily due to higher service restoration costs related to storm activity in the first quarter of 2001.

Equity in earnings of affiliates The $1.2 million increase in equity in earnings of affiliates in 2002 compared to 2001 is primarily due to state tax benefits available to Vermont Yankee as a result of the sale. See Vermont Yankee below for more detail.

Other income, net Variances related to utility and non-utility operations are shown in the following table (dollars in millions) and explained in more detail below.

	2002 vs. 2001	2001 vs. 2000
Utility		
Vermont Yankee sale – one-time payment in 2002	**$(1.0)**	-
Vermont rate case regulatory asset write-off in 2001	**9.0**	$(9.0)
Interest and dividend income	**(1.0)**	(1.4)
Millstone Unit #3 settlement in 2000	**-**	(5.4)
Non-utility		
Catamount revenues and expenses	**3.9**	(0.2)
Catamount asset impairment charges in 2002	**(2.8)**	-
Catamount asset impairment charges in 2001	**8.9**	(8.9)
Catamount asset impairment charges in 2000	**-**	1.0
Eversant (HSS) write-down in 2001	**2.0**	(2.0)
Other	**(0.9)**	1.9
Total Variance	**$18.1**	$(24.0)

Utility: The one-time payment of $1 million is related to closing the Vermont Yankee sale. The $9 million write-off in 2001 is related to the Company's June 26, 2001 Vermont rate order, which is discussed in more detail in Rates and Regulation below. The $5.4 million unfavorable variance for 2001 compared to 2000 was due to the favorable Millstone Unit #3 settlement in 2000.

Non-utility: Catamount net revenues and expenses increased $3.9 million for 2002 versus 2001, related to higher Catamount equity earnings in 2002 from several of Catamount's investments and realized development revenue upon the sale of one of its investments in the fourth quarter of 2002, offset by project development and third-party related costs in 2002. The Catamount asset impairment charges in 2002, 2001 and 2000 are related to asset impairment charges of $2.8 million, $8.9 million and $1 million, respectively. The $2 million Eversant write-down in 2001 is related to its investment in HSS. See Diversification below for more detail.

Interest on long-term debt There was no significant variance in interest on long-term debt in 2002 compared to 2001 or in 2001 compared to 2000. Interest expense reflects the retirement of first mortgage bonds of $7 million in 2002, $4 million in 2001, and $16.5 million in 2000. Interest on long-term debt includes non-utility interest expense of $1.2 million, $1 million and $0.8 million for 2002, 2001 and 2000, respectively.

Other interest expense Other interest expense decreased $1 million in 2002 compared to 2001 and increased $0.6 million in 2001 compared to 2000, primarily due to the 2002 settlement of an IRS audit resulting in the reversal of a related interest expense accrual previously recorded in the fourth quarter of 2001. Other interest expense includes non-utility interest of $0.5 million and $0.1 million for 2001 and 2000, respectively.

Income taxes See Note 11 to the Consolidated Financial Statements for detail regarding fluctuations in the level of expense.

Extraordinary loss, net of tax benefit An extraordinary loss of $0.2 million in the third quarter of 2001 resulted from the application of SFAS No. 71 at Connecticut Valley.

POWER SUPPLY MATTERS

Sources of Energy The Company purchases approximately 90 percent of its power under several contracts of varying duration. The Company's purchased power portfolio includes a mix of base load and schedulable resources and additional wholly owned resources to help cover the Company's peak load periods. A breakdown of the Company's energy sources is shown below:

	2002	2001	2000
Nuclear generating companies	**45%**	43%	43%
Canadian hydro contract	**30**	35	34
Company-owned hydro	**6**	4	6
Jointly owned units	**6**	6	8
Independent power producers	**7**	6	6
Other	**6**	6	3
	100%	100%	100%

The Company's joint-ownership interests include 1.7303 percent in Unit #3 of the Millstone Nuclear Power Station, 20 percent in Joseph C. McNeil, a 53 MW wood-, gas- and oil-fired unit, and 1.78 percent joint-ownership in Wyman #4, a 619 MW oil-fired unit. Wholly owned units include 20 hydroelectric generating units, two oil-fired and one diesel-peaking unit with a combined nameplate capability of 73.6 MW.

The Company has long-term power contracts with Hydro-Quebec and with Vermont Yankee Nuclear Power Corporation ("VYNPC") for a combined total of approximately 85 percent of the Company's total energy (mWh) purchases. Additionally, the Company is required to purchase power from various Independent Power Producers under long-term contracts. See Power Contract Commitments below for more detail regarding these contracts.

The Company also engages in short-term purchases and sales with ISO-New England, and with other electric utilities primarily in New England, in order to minimize the net costs and risk of serving its customers.

Based on present commitments and contracts, the Company expects that net purchased power and production fuel costs will average approximately $133 million to $141 million per year for the years 2003 through 2007, however, these costs are in large part dependent upon wholesale power market prices. The Company's long-term power forecasts indicate a long position, or excess energy to meet load requirements, of approximately 400,000 mWh annually. On a daily basis, the mWh excess is typically sold to ISO-New England with related sales revenue used to offset purchased power expenses. In order to narrow the variance of its forecasted power position, the Company entered into forward sale transactions averaging 312,000 mWh in 2003.

Power Contract Commitments

Hydro-Quebec The Company is purchasing varying amounts of power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract through 2016 and related contracts negotiated between the Company and Hydro-Quebec, which in effect altered the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, including the Company, will "step-up" to the defaulting party's share on a pro rata basis. As of December 31, 2002, the Company's obligation is approximately 46 percent of the total VJO Power Contract through 2016, which translates to approximately $800 million, on a nominal basis, over the contract term. The average annual amount of capacity that the Company will purchase from January 1, 2003 through October 31, 2012 is 143 MW, with lesser amounts purchased through October 31, 2016.

In 2002, the Company purchased approximately $59 million of energy and related capacity under the existing contracts with Hydro-Quebec. The Company's estimated purchases under these contracts at a 75 percent load factor are expected to be approximately $57.7 million, $61.2 million, $61.9 million, $62.5 million and $62.9 million for the years 2003 through 2007, respectively. See Note 13 to the Consolidated Financial Statements for further discussion of this contract.

Vermont Yankee On July 31, 2002, VYNPC completed the sale of the Vermont Yankee nuclear power plant to Entergy Nuclear Vermont Yankee, LLC ("Entergy"). The sale transaction included a purchased power contract ("PPA") with prices that generally range from 3.9 cents to 4.5 cents per kilowatt-hour through 2012, subject to a "low-market adjuster" effective November 2005, that protects the current Vermont Yankee owner-utilities, including the Company and its power consumers, in the event power market prices drop significantly. If the market prices rise, however, contract prices are not adjusted upward. The PPA is forecasted to result in higher purchased power costs in the initial years of the contract with decreased costs in future years when compared to continued ownership of the plant.

The Company receives its 35 percent entitlement of Vermont Yankee output sold by Entergy to VYNPC. Under the PPA between Entergy and VYNPC, VYNPC pays Entergy only for generation at fixed rates; VYNPC in turn includes the PPA charges from Entergy with certain residual costs of service through a FERC tariff to the Company and the other VYNPC sponsors. Accordingly, as a result of the sale, the Company no longer bears the operating costs and risks associated with running the plant or the costs and risks associated with the eventual decommissioning of the plant.

In 2002 the Company purchased approximately $60.2 million of energy and capacity from Vermont Yankee, based on its entitlement share in the plant before and after the sale. The Company's estimated purchases related to Vermont Yankee are expected to be approximately $65.9 million, $61.5 million, $56.7 million, $60.7 million and $56 million for the years 2003 through 2007, respectively.

Independent Power Producers ("IPPs") The Company purchases power from a number of IPPs who own qualifying facilities under the Public Utility Regulatory Policies Act of 1978. These qualifying facilities produce energy using hydroelectric, biomass and refuse-burning generation. The majority of these purchases are made from a state-appointed purchasing agent who purchases and redistributes the power to all Vermont utilities.

In 2002, the Company received 198,371 mWh under these long-term contracts, representing approximately 7.6 percent and 15 percent of the Company's total mWh purchases and total purchased power expense for the period, respectively. The total mWh received under these contracts includes 145,572 mWh allocated by the Purchasing Agent, VEPP Inc., and 36,675 mWh purchased by Connecticut Valley from a waste-to-energy electric generating facility owned by Wheelabrator Claremont Company, L.P. The Company's estimated purchases from IPPs are expected to be approximately $22.5 million, $22.8 million, $22.3 million, $22.8 million and $21.1 million for the years 2003 through 2007, respectively.

See Note 12 and Note 13 to the Consolidated Financial Statements for additional information regarding Wheelabrator and contract negotiations with IPPs, respectively.

Wholly Owned Generating Units The Company owns and operates 20 hydroelectric generating units, two gas turbines and one diesel peaking unit with a combined nameplate capability of 73.6 MW.

The Company is currently in the process of relicensing or preparing to relicense six separate hydroelectric projects under the Federal Power Act. These projects, some of which are grouped together under a single license, represent approximately 24.5 MW, or about 54.8 percent of the Company's total hydroelectric nameplate capacity. In the new licenses, the FERC is expected to impose conditions designed to address the impact of the projects on fish and other environmental concerns. The Company is unable to predict the specific impact of the imposition of such conditions, but capital expenditures and operating costs are expected to increase in the short term to meet these licensing obligations and net generation from these projects will decrease in future periods.

Peterson Dam The Company has worked with environmental groups and the State of Vermont since 1998 to develop a plan to relicense Peterson Dam, a 6.35-MW hydroelectric station on the Lamoille River. The Vermont Natural Resources Council ("VNRC") and others proposed removal of the 1948 facility, which produces power to energize approximately 3,000 homes per year. In April 2002, the parties including the Town of Milton and the DPS entered into a Conceptual Agreement outlining a negotiated settlement of the issues relating to project relicensing, including the removal of Peterson Dam.

In January 2003, the Company, the State of Vermont, VNRC and other parties reached an agreement to allow the Company to relicense the four dams owned and operated by the Company on the Lamoille River. According to the agreement, the Company will receive a water quality certificate from the State, which is needed for the FERC to relicense the facilities for 30 years. The agreement also stipulates that the Company must begin decommissioning Peterson Dam in approximately 20 years. The agreement, however, requires PSB approval of full rate recovery related to decommissioning Peterson Dam including full rate recovery of replacement power costs when the dam is out of service. The Company cannot predict the outcome of this matter.

Nuclear Decommissioning The Company is responsible for paying its joint-ownership percentage of Millstone Unit #3 decommissioning costs and its entitlement percentages of decommissioning costs related to Maine Yankee, Connecticut Yankee and Yankee Atomic (the "Yankee companies").

Millstone Unit #3 The Company has a 1.7303 percent joint-ownership interest in the Millstone Unit #3 facility, in which Dominion Nuclear Corporation ("DNC") is the lead owner with approximately 93.47 percent of the plant joint-ownership. The Company is responsible for its joint-ownership share of decommissioning costs. The Company's contributions to the Millstone Unit #3 Trust Fund have ceased based on DNC's representation to various regulatory bodies that the Trust Fund, for its share of the plant, exceeded the Nuclear Regulatory Commission's ("NRC") minimum calculation required. The Company could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded.

In accordance with ratemaking treatment, the incremental costs attributable to replacement energy and maintenance costs, incurred during regular nuclear refueling outages, are deferred and amortized ratably to expense until the next regularly scheduled refueling outage, which is typically over 18 months. Millstone Unit #3 had a scheduled refueling outage in early 2001 and another in September 2002. The Company deferred approximately $1 million for energy and maintenance costs related to the September 2002 refueling outage.

Yankee Companies The Yankee companies have been permanently shut down and are currently conducting decommissioning activities. Each plant revises its revenue requirement forecasts on an ongoing basis, including estimates for decommissioning costs, based on site-specific studies, through the projected completion date of all decommissioning activity. Based on revised estimates in 2002, the costs of decommissioning Maine Yankee, Connecticut Yankee and Yankee Atomic increased by $40 million, $150 million and $190 million, respectively, over prior estimates utilized at the FERC. These increased costs are attributable mainly to increases in the projected costs of spent fuel storage, security and liability and property insurance.

The Company's share of estimated future payments related to the decommissioning efforts based on current forecasts, including the incremental cost increases described above, are as follows (dollars in millions):

	Date of Study	Estimated Obligation (a)	Revenue Requirements (b)	Company Share
Maine Yankee	2002	$359.4	$441.9	$9.0
Connecticut Yankee	2002	$414.1	$366.0	$7.3
Yankee Atomic	2002	$321.0	$224.9	$7.9

(a) Represents estimated remaining decommissioning costs, for the period 2002 through 2022 for Yankee Atomic and through 2023 for Maine Yankee and Connecticut Yankee, in 2002 dollars.

(b) Revenue requirements reflect the future payments required by the sponsor companies to recover estimated decommissioning and all other costs in nominal dollars, except for Yankee Atomic, which has collected all other costs except for the increased estimated decommissioning costs described above.

The Company's share of estimated revenue requirements are reflected on the Consolidated Balance Sheets as either regulatory assets or other deferred charges, depending on current recovery in existing rates, and nuclear decommissioning liabilities (current and non-current). At December 31, 2002, the Company had regulatory assets of approximately $9 million and $3.8 million related to Maine Yankee and Connecticut Yankee, respectively, and other deferred charges of $3.5 million and $7.9 million related to Connecticut Yankee and Yankee Atomic, respectively. These amounts are subject to ongoing review and revisions and the Company adjusts the associated regulatory assets, other deferred charges and nuclear decommissioning liabilities accordingly.

The decision to prematurely retire these nuclear power plants was based on economic analyses of the costs of operating them compared to the costs of closing them and incurring replacement power costs over the remaining period of the plants' operating licenses. The Company believes that the premature retirements would have the effect of lowering costs to customers. The Company believes that based on the current regulatory process, its proportionate share of Maine Yankee's, Connecticut Yankee's and Yankee Atomic's decommissioning costs will be recovered through the regulatory process. Therefore, the ultimate resolution of the premature retirement of the three plants has not and should not have a material adverse effect on the Company's earnings or financial condition.

Maine Yankee In 1997, the Maine Yankee nuclear power plant was prematurely retired from commercial operation. The Company relied on Maine Yankee for less than 5 percent of its required system capacity. Currently, costs billed to the Company by Maine Yankee, including a provision for ultimate decommissioning of the plant, are expected to be paid over the period 2003 through 2008, and are being collected from the Company's customers through existing retail and wholesale rate tariffs.

Maine Yankee's current billings to the sponsor companies are based on its most recent rate case settlement, approved by the FERC on June 1, 1999. The settlement provides for recovery of anticipated future payments for closing, decommissioning and recovery of the remaining investment in Maine Yankee and also resolved all issues raised in the FERC proceeding, including those raised by the secondary purchasers, who purchased Maine Yankee power through agreements with the original owners. Under the rate case settlement, Maine Yankee agreed to file with the FERC a rate proceeding with an effective date for new rates of no later than January 1, 2004. Maine Yankee is expected to seek recovery of the incremental cost increase described above in its next FERC rate filing.

Connecticut Yankee In 1996, the Connecticut Yankee nuclear power plant was prematurely retired from commercial operation. The Company relied on Connecticut Yankee for less than 3 percent of its required system capacity. Currently, costs billed to the Company by Connecticut Yankee, including a provision for ultimate decommissioning of the plant, are expected to be paid over the period 2003 through 2007 and are being collected from the Company's customers through existing retail and wholesale rate tariffs.

Connecticut Yankee's current billings to the sponsor companies are based on its most recent FERC approved rates, which became effective September 1, 2000. Connecticut Yankee is expected to seek recovery of the incremental cost increase described above in its next scheduled FERC rate filing.

Yankee Atomic In 1992, the Yankee Atomic nuclear power plant was retired from commercial operation. The Company relied on Yankee Atomic for less than 1.5 percent of its system capacity. Costs related to Yankee Atomic are not included in the Company's existing rates due to Yankee Atomic's determination in July 2001 that it had collected sufficient funds to complete the decommissioning effort and discontinued related billings to the sponsor companies at that time. Changes to decommissioning cost estimates, however, are subject to ongoing review and such changes would require FERC review and approval.

Yankee Atomic plans to file its rate application with the FERC for recovery of the incremental cost increase described above in March 2003. Billings to sponsors for recovery of these costs are expected to resume in June 2003, for recovery through 2010.

LIQUIDITY AND CAPITAL RESOURCES

The Company ended 2002 with cash and cash equivalents of $60.4 million, an increase of $14.9 million from December 31, 2001. The increase resulted from $42.6 million provided by operating activities, $0.1 million provided by the effect of exchange rate changes on cash, offset by $2 million used for investing and $25.8 million used for financing. The Company ended 2001 with cash and cash equivalents of $45.5 million, a decrease of $2.5 million from the beginning of the year resulting from $30.2 million provided by operating activities, offset by $30.6 million used for investing activities and $2.1 million used for financing activities.

The Company's liquidity is primarily affected by the level of cash generated from operations, reduced by the funding requirements of its ongoing construction programs. The Company believes that it will generate sufficient cash flow from operations to fund its anticipated needs through at least 2004. The $75 million Second Mortgage Bonds mature on August 1, 2004. It is currently anticipated that all or a majority of the debt will be refinanced at maturity. The type, timing and terms of future financing that the Company may need will depend upon its cash needs, the availability of refinancing sources and the prevailing conditions in the financial markets.

2002 vs. 2001

Operating Activities Net income, depreciation, deferred income taxes and investment tax credits, including after-tax non-cash items of $2.8 million related to Catamount's asset impairment charges and $12.1 million related to deferrals of the Vermont Yankee fuel rod maintenance and sale-related costs, provided cash of $30.6 million. Working capital and other operating activities provided approximately $12 million of cash.

Investing Activities Construction and plant expenditures used cash of approximately $14.4 million, Conservation and Load Management programs used $0.2 million, investment in VELCO used $0.4 million and other investing activities used $0.3 million, while $13 million was provided by non-utility investments, mostly related to the sale of Catamount's investments in Gauley River and Heartlands and $0.3 million was provided by the return of capital from utility investments.

The Company's five-year capital expenditures for the Vermont utility business are expected to range from approximately $85 million to $90 million for the years 2003 through 2007.

Financing Activities Dividends paid on common stock were $10.3 million, while preferred stock dividends were $1.9 million. The pay down of capital lease obligations required $1.1 million, while the retirement of long-term debt and preferred stock used $14.2 million. The Company's dividend reinvestment program provided $1.3 million and sale of common stock from the Company's Treasury shares provided $0.4 million.

Effect of Exchange Rate Changes on Cash Net cash flow provided by the effect of exchange rate changes on cash was $0.1 million. The increase was the result of Catamount's foreign currency translations.

2001 vs. 2000

Operating Activities Net income and depreciation, including after-tax non-cash items of $16.2 million related to the regulatory asset write-off, Catamount's asset impairment charges and Eversant's investment write-down, provided cash of $35.6 million. Approximately $5.4 million of cash was used for working capital and other operating activities.

Investing Activities Construction and plant expenditures used cash of approximately $16.6 million and Conservation and Load Management programs used $0.5 million, while $13.7 million was used for non-utility investments mostly related to Catamount's investment in Gauley River. Other investing activities provided $0.2 million.

Financing Activities Dividends paid on common stock were $10.1 million, while preferred stock dividends were $1.3 million. The pay down of capital lease obligations required $1.1 million, while net long-term debt contributed $9.8 million and sale of common stock from the Company's Treasury shares provided $0.6 million.

Obligations The following table is a summary of the Company's obligations as of December 31, 2002.

		Payments Due by Period (millions of dollars)			
Contractual Obligations	Total	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years
Long-term Debt - utility	$137.3	$10.5	$75.0	-	$51.8
Long-term Debt - non-utility	21.5	10.4	11.1	-	-
Preferred Stock	18.1	-	2.0	$2.0	14.1
Purchased Power Contracts (a)	1,646.1	146.1	286.4	286.0	927.6
Capital Lease	12.9	1.1	2.2	2.2	7.4
Total Contractual Obligations	$1,835.9	$168.1	$376.7	$290.2	$1,000.9

(a) Includes power contract commitments with Hydro-Quebec, VYNPC and IPPs. The costs associated with these obligations are currently being collected in rates. See Power Supply Matters above for more information related to these contracts.

Utility

Based on outstanding debt at December 31, 2002, the aggregate amount of utility long-term debt maturities and sinking fund requirements are $10.5 million and $75 million for the years 2003 and 2004. No payments are due for 2005 through 2007. It is currently anticipated that all, or a majority of, the $75 million Second Mortgage Bonds, maturing at August 1, 2004, will be refinanced at maturity. Substantially all of the Company's Vermont utility property and plant is subject to liens under the First and Second Mortgage Bonds.

The Company has an aggregate of $16.9 million of letters of credit with Citizen's Bank of Massachusetts, expiring on August 31, 2003. These letters of credit support three series of Industrial Development/Pollution Control Bonds, totaling $16.3 million. The letter of credit supporting the $5.5 million Seabrook bonds was effective on August 22, 2002. The Company had in place a supplemental indenture allowing the letter of credit to transfer. These letters of credit are secured by a first mortgage lien on the same collateral supporting the Company's first mortgage bonds.

The Company's long-term debt arrangements contain financial and non-financial covenants. At December 31, 2002, the Company was in compliance with all debt covenants related to its various debt agreements.

Non-Utility

Catamount has a $25 million revolving credit/term loan facility and letters of credit, of which $21.3 million was outstanding at December 31, 2002. The facility expired on November 12, 2002 and on December 31, 2002 Catamount and its lender entered into the First Amendment to the facility that, among other things, extended the revolver facility for an additional two years. Under the two-year extension, Catamount can borrow against new operating projects subject to the terms and conditions of the facility. Additionally, the outstanding revolver loans were converted to amortizing loans on a two-year term-out schedule. The interest rate is variable, prime-based. Catamount's assets secure the facility. Based on total outstanding debt of $21.5 million at December 31, 2002, including Catamount's office building mortgage, the aggregate amount of Catamount's long-term debt maturities are $10.4 million and $11.1 million for the years 2003 and 2004, respectively. Catamount's long-term debt contains financial and non-financial covenants. Catamount received a waiver by the lender on October 31, 2002 for capital expenditures that exceeded the annual budget. At December 31, 2002, Catamount was in compliance with all covenants under the revolver. In early January 2003, Catamount applied $12.6 million, representing the after-tax proceeds from its investment sales, against its outstanding loan balance resulting in a $8.7 million loan balance.

Eversant In 2002, SmartEnergy Water Heating Services, Inc., a wholly owned subsidiary of Eversant, retired a $1.1 million term loan with Bank of New Hampshire.

Capital Structure The Company's capital ratios (including amounts of long-term debt due within one year) for the past three years were as follows:

	December 31		
	2002	2001	2000
Common stock equity	**51%**	47%	49%
Preferred stock	**5**	6	6
Long-term debt	**41**	43	41
Capital lease obligations	**3**	4	4
	100%	100%	100%

Credit Ratings Current credit ratings of the Company's securities by Standard & Poor's and Fitch IBCA ("Fitch") were reaffirmed during 2002. The rating affirmations reflect improvement in the Company, subsequent to the sale of the Company's interest in the Vermont Yankee nuclear plant, due to reduced business risk and the Company's ability to recover all purchased power costs in rates. Credit ratings should not be considered a recommendation to purchase stock. Current credit ratings are as follows:

	Standard & Poor's (1)	Fitch (2)
Corporate Credit Rating	BBB-	N/A
First Mortgage Bonds	BBB+	BBB
Second Mortgage Bonds	BBB-	BBB-
Preferred Stock	BB	BB+

(1) Outlook: Stable (2) Outlook: Stable

DIVERSIFICATION

Catamount Resources Corporation was formed for the purpose of holding the Company's subsidiaries that invest in non-regulated business opportunities including Catamount and Eversant.

Catamount Catamount invests through its wholly owned subsidiaries in non-regulated energy generation projects in the United States and Western Europe. As of December 31, 2002, through its wholly owned subsidiaries, Catamount has interests in eight operating independent power projects located in Glenns Ferry and Rupert, Idaho; Rumford, Maine; East Ryegate, Vermont; Thetford, England; Hopewell, Virginia; Thuringen, Germany and Mecklenburg-Vorpommern, Germany.

In 2001, Catamount undertook a comprehensive strategic review of its operations and refocused its efforts from being an investor in late-stage renewable energy to being primarily focused on developing, owning and operating wind energy projects. Wind energy is competitive with other forms of electric generation and has low production costs compared to other renewable energy sources. Environmental and energy security concerns support growth in the wind sector. Catamount is currently pursuing the sale of certain of its interests in non-wind electric generating assets. Proceeds from sales will be used to either pay down the outstanding loan balance or be reinvested in the development of new wind projects, as well as the acquisition of existing wind projects. Additionally, Catamount is seeking investors and partners to co-invest with Catamount in the development, ownership and acquisition of projects, which will be financed by equity and non-recourse debt. Management cannot predict the timing or outcome of potential future asset sales or whether this new strategy will be successful.

In June 2001, Catamount established Catamount Development GmbH, a German corporate entity, 100 percent owned by Catamount Heartlands Corp., a wholly owned subsidary of Catamount. The company was formed to hold Catamount's interests in German "greenfield" development projects that would be purchased by Catamount in early to mid-stage development.

In 2002, Catamount established Catamount Energy Ltd., a UK and Wales limited company, which is ultimately 100 percent owned by two of Catamount's wholly owned subsidiaries. The company was formed to hold Catamount's interests in UK "greenfield" development projects or projects that would be purchased by Catamount in early to mid-stage development.

Catamount's earnings were $1.5 million for 2002 and its loss and earnings were $8.7 million and $0.7 million for 2001 and 2000, respectively. See Competition – Risk Factors below and Note 3 to the Consolidated Financial Statements for more information regarding Catamount.

Eversant Eversant has a $1.4 million equity investment, representing a 12.1 percent ownership interest in The Home Service Store, Inc. ("HSS"), as of December 31, 2002. HSS has established a network of affiliate contractors who perform home maintenance repair and improvements for HSS members. HSS began operations in 1999 and is subject to risks and challenges similar to a company in the early stage of development. In September 2001, Eversant recorded a $1.2 million after-tax write-down of its investment in HSS to fair value. Eversant had previously recorded losses of $9 million related to its investment in HSS. Eversant accounts for its investment in HSS on a cost basis.

During 2001, AgEnergy (formerly SmartEnergy Control Systems), a wholly owned subsidiary of Eversant, filed a claim in arbitration against Westfalia-Surge, the exclusive distributor that marketed and sold its SmartDrive Control product. The arbitration concerned the Company's claim that Westfalia-Surge had not conducted itself in accordance with the exclusive distributorship agreement between the parties. On January 28, 2002, the Company received an adverse decision related to the arbitration proceeding with Westfalia-Surge. On November 6, 2002, Westfalia filed a Petition to Confirm the Arbitrator's Award in the United States District Court for the Western District of Wisconsin, which effectively sought to expand the Arbitrator's Award. The Company submitted an answer seeking to dismiss the Petition to the extent it sought costs in excess of those established by the Arbitrator. The Company cannot predict the outcome of the proceeding.

SmartEnergy Water Heating Services, Inc. ("SEWHS") had earnings of $0.3 million, $0.4 million and $0.5 million for 2002, 2001 and 2000, respectively.

In the first quarter of 2002, the Company decided to discontinue Eversant's efforts to pursue non-regulated business opportunities but will continue its water heating business through SEWHS. Overall, Eversant incurred net losses of $0.5 million, $2.1 million and $2.3 million for 2002, 2001 and 2000, respectively. See Note 3 to the Consolidated Financial Statements for more information regarding Eversant.

RATES AND REGULATION

The Company recognizes that adequate and timely rate relief is necessary if it is to maintain its financial strength, particularly since Vermont regulatory rules do not allow for changes in purchased power and fuel costs to be automatically passed on to consumers through rate adjustment clauses. The Company intends to continue its practice of periodically reviewing costs and requesting rate increases when warranted. The Company currently plans, absent any unforeseen developments, to refrain from changing rates for its Vermont utility customers until at least 2006.

Vermont Retail Rates

2000 Retail Rate Case In an effort to mitigate eroding earnings and cash flow prospects, on November 9, 2000, the Company filed with the PSB a request for a 7.6 percent rate increase, or $19 million per annum, effective July 24, 2001. The PSB suspended the rate filing and a schedule was set to review the case.

On June 26, 2001, the PSB issued an order approving the Company's May 7, 2001, rate case settlement with the DPS. The rate order ended uncertainty over the future recovery of Hydro-Quebec contract costs, allowed a 3.95 percent rate increase, made the January 1, 1999 temporary rates permanent, permitted a return on equity of 11.0 percent for the 12 months ending June 30, 2002, for the Vermont utility, and created new service quality standards. The Company also agreed to a $9 million one-time write-off ($5.3 million after-tax) of regulatory assets, which was recorded in June 2001, and a rate freeze through January 1, 2003.

In addition to the provisions outlined above, the rate order requires the Company to return up to $16 million to ratepayers in the event of a merger, acquisition or asset sale if such sale requires PSB approval. The 3.95 percent rate increase became effective with bills rendered July 1, 2001.

As part of the Company's June 26, 2001 rate order, the Company agreed that all amounts collected from the Hydro-Quebec Ice Storm settlement would be applied first to reduce the remaining balance of deferred costs related to the arbitration, with the remaining balance, if any, applied to reduce other regulatory asset accounts as specified by the DPS and approved by the PSB. In July 2001 Hydro-Quebec and the VJO agreed to a final settlement, of which the Company's share was approximately $4.3 million. In the third quarter of 2001, the Company applied approximately $2.7 million to the remaining balance of deferred ice storm arbitration costs. On October 30, 2001, the Company filed a letter with the PSB summarizing its agreement with the DPS on application of the remaining $1.6 million to other regulatory assets. On September 10, 2002 and in response to a PSB request, the Company filed its amended proposal as agreed to with the DPS.

On October 4, 2002, the PSB issued an Order approving the Company's proposal for reducing certain regulatory assets by approximately $2 million through application of the remaining Hydro-Quebec settlement and the ongoing Millstone Unit #3 decommissioning non-payments. Although the Company is recovering the Millstone Unit #3 decommissioning costs in rates, its payments for decommissioning have ceased. In the third quarter of 2002, based on the PSB Order, the Company reduced certain of its regulatory assets related to Conservation and Load Management by approximately $2 million. The Company will account for the ongoing Millstone Unit #3 decommissioning non-payments as a regulatory liability, with carrying charges, to be addressed in the Company's next rate proceeding.

In 2002, the Vermont utility earned approximately $0.4 million, on an after-tax basis, above its allowed rate of return of 11.0 percent. In accordance with its rate case settlement, the Company reduced the Vermont utility's earnings by that amount to satisfy its earnings cap requirement. The related deferral of approximately $0.7 million pre-tax is included in Other deferred credits on the Company's Consolidated Balance Sheet. The Company and DPS are currently in discussions as to the balance sheet classification so as to preserve ratepayer benefit as required by the rate case settlement.

See Note 12 to the Consolidated Financial Statements for more detail related to Vermont retail rates.

New Hampshire Retail Rates

Connecticut Valley's retail rate tariffs, approved by the New Hampshire Public Utilities Commission ("NHPUC") contain a Fuel Adjustment Clause ("FAC"), and a Purchased Power Cost Adjustment ("PPCA"). Under these clauses, Connecticut Valley recovers its estimated annual costs for purchased energy and capacity, which are reconciled when actual data is available.

See Note 12 to the Consolidated Financial Statements for more detail related to New Hampshire retail rates.

Connecticut Valley Sale On December 5, 2002, the Company reached agreement for the sale of Connecticut Valley to Public Service Company of New Hampshire ("PSNH"), New Hampshire's largest electric utility. The sale agreement is the result of months of negotiations among Connecticut Valley, the Company, the Governor's Office of Energy and Community Services, staff of the NHPUC, the Office of Consumer Advocate, the City of Claremont and New Hampshire Legal Assistance. Management believes the sale agreement, as structured, should resolve all issues in litigation over New Hampshire's restructuring plan, Connecticut Valley's rates, recovery of stranded costs and renders moot a pending exit fee decision by the FERC. The proposed closing date for the sale is January 1, 2004.

Under the terms of the sale agreement, PSNH will pay the Company the book value for Connecticut Valley's franchise utility assets, which approximates $9 million at December 31, 2002. PSNH will acquire Connecticut Valley's poles, wires, substations and other facilities, as well as several independent power obligations, including the Wheelabrator contract. Contemporaneously with the sale, PSNH will pay an additional $21 million to the Company as a stranded cost reimbursement for the power resources the Company acquired to serve Connecticut Valley's customers.

The FERC, the NHPUC and possibly the SEC must approve the sale. In addition, as a condition of the sale, the NHPUC must approve the pending settlement in the Wheelabrator docket.

The sale will result in either a gain or loss; however, the nature and size of such gain or loss will be highly dependent upon power market price forecasts at the time of the sale and mitigation efforts both before and after the sale. Accordingly, the Company cannot estimate at this time such a gain or loss.

If the sale transaction does not close, and if there is an adverse resolution of the pending FERC exit fee proceeding, these events would have a material adverse effect on the Company's results of operations, financial condition and cash flows. However, the Company cannot predict the ultimate outcome of this matter.

FERC Exit Fee Proceedings On February 28, 1997, Connecticut Valley was directed by the NHPUC to terminate its purchase of power from the Company. The Company filed an application with the FERC in June 1997, to recover stranded costs in connection with its wholesale rate schedule with Connecticut Valley and the notice of cancellation of that rate schedule (contingent upon the recovery of the stranded costs that would result from the cancellation of that rate schedule). In December 1997, the FERC rejected the Company's proposal to recover stranded costs through the imposition of a surcharge in the Company's transmission tariff, but indicated that it would consider an exit fee mechanism in the wholesale rate schedule for collecting stranded costs. The FERC denied the Company's motion for a rehearing regarding the transmission surcharge proposal. However, the Company filed a request with the FERC for an exit fee mechanism in the wholesale rate schedule to collect the stranded costs resulting from the cancellation of the wholesale rate schedule. The stranded cost obligation sought to be recovered was $90.6 million in nominal dollars and $44.9 million on a net present value basis as of December 31, 1997.

On April 24, 2001, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision in the Company's stranded cost/exit fee proceeding. The ALJ ruled that if Connecticut Valley terminates its relationship as a wholesale customer of the Company and subsequently becomes a wholesale transmission customer of the Company, Connecticut Valley shall be liable for payment of stranded costs to the Company. The ALJ calculated, on an illustrative pro-forma basis, a nominal stranded cost obligation of nearly $83 million through 2016. The amount of the exit fee as determined by the ALJ will decrease with each year that service continues and normal tariff revenues are collected, and will ultimately be calculated from the date of termination, if notice of termination is ever given.

On October 29, 2002, the Company, jointly with the NHPUC, requested that the FERC defer issuance of its final exit fee order to allow for Connecticut Valley to continue working for a negotiated settlement with parties to the New Hampshire restructuring proceeding and the NHPUC. On December 5, 2002, Connecticut Valley, the State of New Hampshire, the City of Claremont and PSNH reached agreement for the sale of Connecticut Valley to PSNH. Under the terms of the agreement, which is described in more detail above, PSNH will pay an additional $21 million to the Company as a stranded cost reimbursement for the power resources the Company acquired to serve Connecticut Valley's customers, thus rendering moot the exit fee decision by the FERC.

Absent the sale, if the Company was unable to obtain approval by the FERC of an exit fee from its power supply arrangement and Connecticut Valley was forced to terminate its relationship as a wholesale customer of the Company (the earliest termination date that could presently occur pursuant to the wholesale rate schedule is December 31, 2004) it is possible that the Company would be required to recognize a pre-tax loss under the power supply arrangement totaling approximately $27.4 million as of December 31, 2004. The Company would also be required to write-off approximately $0.6 million pre-tax of regulatory assets associated with its wholesale business as of December 31, 2004. The sale of Connecticut Valley to PSNH as currently structured, which includes the receipt of $21 million in stranded cost recovery, is expected to resolve these issues. However, Management cannot predict whether the sale will occur under these terms.

Wheelabrator Power Contract Connecticut Valley purchases power from several Independent Power Producers, who own qualifying facilities as defined by the Public Utility Regulatory Policies Act of 1978. For the 12 months ended December 31, 2002, under long-term contracts with these qualifying facilities, Connecticut Valley purchased 39,258 mWh, of which 93 percent was purchased from Wheelabrator Claremont Company, L.P., ("Wheelabrator") who owns a waste-to-energy electric generating facility. Connecticut Valley had filed a complaint with the FERC stating its concern that Wheelabrator has not been a qualifying facility since the facility began operation. On February 11, 1998, the FERC issued an Order denying Connecticut Valley's request for a refund of past purchased power costs and lower future costs. Connecticut Valley filed a request for rehearing with the FERC on March 13, 1998, which was denied. Connecticut Valley appealed to the D.C. Circuit Court of Appeals, which denied the appeal, but indicated that Connecticut Valley could seek relief from the NHPUC. On May 12, 2000, Connecticut Valley filed a petition with the NHPUC seeking 1) to amend the contract to permit purchase of net, rather than gross, output of the facility and 2) a refund, with interest, of past purchases of the difference between net and gross output.

On March 29, 2002, the NHPUC issued an order denying Connecticut Valley's petition. The NHPUC further found that its original 1983 order did not authorize sales in excess of 3.6 MW and ordered that Connecticut Valley discontinue purchases in excess of that amount at preferential rates. Wheelabrator has been making sales at the long-term rates for up to 4.5 MW of capacity and related energy since it began operations in 1987.

On April 29, 2002, Connecticut Valley, Wheelabrator, NHPUC Staff and the Office of Consumer Advocate submitted a Stipulation of Settlement with the NHPUC that requires Wheelabrator to make five annual payments of $150,000 and a sixth payment of $25,000, and Connecticut Valley to make six annual payments of $10,000, all of which will be credited to customer bills. The Stipulation of Settlement will not become effective unless and until it is approved by the NHPUC. The settlement does not otherwise change the terms of the existing contract between Connecticut Valley and Wheelabrator.

A hearing on the Stipulation of Settlement was held on June 7, 2002 with a focus on determining whether the Stipulation is in the public interest. The NHPUC issued an Order on July 5, 2002, in which it did not rule on the Stipulation of Settlement and instead announced that it would appoint an independent mediator to work with all parties to see if a mutually agreeable settlement of the case could be achieved. The NHPUC selected an independent mediator and, after several mediation sessions, the mediator issued a report on December 18, 2002, which stated that the parties opposing the Stipulation of Settlement before the mediation continued to oppose it after the mediation.

As a condition to the sale of Connecticut Valley to PSNH, the NHPUC must approve the Stipulation of Settlement. Additionally, under the terms of the sale agreement, PSNH will acquire several of Connecticut Valley's independent power obligations, including the Wheelabrator contract.

ELECTRIC INDUSTRY RESTRUCTURING

The electric utility industry is in a period of transition that in some cases has resulted in a shift away from ratemaking based on cost of service and return on equity to more market-based rates with energy sold to customers by competing retail energy service providers. Many states, including New Hampshire, where the Company does business, have implemented new mechanisms to bring greater competition, customer choice and market influence to the industry while retaining the public benefits associated with the current regulatory system. During 2001, however, the pace of transition slowed due primarily to public and governmental reactions to issues associated with deregulation efforts in California and the collapse of its wholesale electricity market.

Vermont There have been three primary sources of Vermont governmental activity attempting to restructure the electric industry in Vermont: 1) the Governor's Working Group, created by the former Governor of Vermont, which completed its work in 1998; 2) the PSB's Docket No. 6140 through which the PSB considered proposals to restructure committed utility power supply arrangements; and 3) the PSB's Docket No. 6330, through which the PSB considered the establishment of policies and procedures to govern retail competition within the Company's service territory. At this time, the PSB has concluded its investigation into the restructuring of committed power supply arrangements in Docket No. 6140 and the proceeding has been closed. Additionally, in December 2001, the PSB issued an order closing Docket No. 6330. As a result, the Company cannot determine when or if retail competition will be introduced within the Company's Vermont service territory.

Regional Transmission Organizations Pursuant to FERC Order No. 888 (issued April 1996) the Company operates its transmission system under an open access, nondiscriminatory transmission tariff.

In 1999, the FERC issued a Notice of Proposed Rulemaking ("NOPR") that would amend FERC's regulations under the Federal Power Act to facilitate the formation of regional transmission organizations ("RTO"). In late 1999 the FERC issued Order No. 2000, regarding the formation of RTOs. The Company has participated in various filings and proceedings related to formation of RTOs since Order No. 2000 was first issued. More recently, on November 22, 2002, NEPOOL notified the FERC that it was withdrawing the proposal made with New York to form the Northeast RTO and, subsequently, announced that it would propose an RTO for New England. It is anticipated that this filing will be made mid-year 2003. Transmission-owning entities in New England, including Vermont Electric Power Company, Inc. ("VELCO") and the Company, are participating in discussions intended to result in a transmission network company to provide the transmission services needed under the FERC's RTO Order.

Order No. 2000 is generally designed to separate the governance and operation of the transmission system from generation companies and other market participants. At this time, the Company is unable to predict the outcome of this matter or its impact on the Company.

Standard Market Design On July 31, 2002, FERC issued a NOPR for Standard Market Design ("SMD"). FERC intends to establish nationally consistent power market rules and offers additional options for RTO formation. On September 20, 2002, the FERC accepted in part ISO-New England's request to implement an SMD governing wholesale energy sales in New England. The SMD will include a system of locational marginal pricing of energy under which prices for load will be determined by zone and based in part on transmission congestion and marginal losses experienced in each zone. Previous to SMD the costs of network congestion and losses were spread across the region's load-serving entities on a pro rata basis. Based on data observed during indicative trials beginning in the fall of 2002, congestion appears to be most significant in the load centers of eastern Massachusetts and southwestern Connecticut, while losses may be high in Vermont. Initially, the State of Vermont is expected to comprise a single load zone under the plan. Generators will receive location-specific prices for the nodes at which they interconnect with the New England electric network. The vast majority of the Company's generating resources are either located in the Vermont Zone or delivered at locations that are not expected to congest significantly in or en route to the Vermont Zone under expected circumstances. Because of their magnitude, congestion and loss costs are the two categories of power related costs that have the greatest potential to increase or decrease the net cost of serving load relative to the pre-SMD environment. An auction-based system of Financial Transmission Rights ("FTR") will be implemented to allow participants to hedge congestion risks. An associated auction revenue allocation scheme will be implemented to distribute the proceeds of the FTR auction to load entities that experience congestion and entities that invest to increase the capacity of the regional network.

SMD will also include the creation of a location-specific day-ahead market that will allow participants the opportunity to settle transactions involving load and generation one day in advance of the real time spot market. In general, the Company either owns or holds entitlements to generation that will be self-scheduled in the day-ahead market and, therefore, anticipates making use of that market to clear the majority of its load and generation. The Company expects that its remaining dispatchable resources and residual load will settle in the real-time market. The overall price level and volatility of these new markets cannot be determined at this time; however, the Company expects to employ available risk mitigation mechanisms and its largely firm-priced sources to limit the effects.

Administrative fees applied by the ISO to transactions are also being changed to reflect greater costs of SMD. The Company believes that in total the administrative costs of SMD will be greater than prior market configurations. Separately, the Company, through VYNPC, is engaged in discussions with Entergy, which owns the Vermont Yankee plant, over transaction settlement procedures, allocation of transaction costs and volumetric measures charges under the SMD.

Operating reserve requirements are also changing and, in general, the Company expects the new requirements are likely to somewhat raise costs relative to the system operating reserve requirements in place prior to SMD. ISO-New England has also increased the financial assurance requirement for all entities participating in the market based upon each entity's credit rating and current net position. The Company anticipates that additional credit related costs, relative to the pre-SMD market, are likely to be incurred in order to satisfy this requirement.

The rules requiring load-serving entities to hold generating capacity based upon peak demands in the region are also being revamped. Going forward, this responsibility will be determined by each entity's share of the New England peak load over a trailing annual period. In general, the Region tends to experience its peaks in summer months while the Company's maximum loads tend to occur in the months of December and January. The capacity credit received for generation is also being modified to further account for the observed operating performance of the specific sources. In general, the Company believes that its resources demonstrate operating reliability that is relatively favorable to the population of generators in the region.

On February 6, 2003, ISO-New England announced that SMD would become operational on March 1, 2003. ISO New England is also working with the region's stakeholders to propose to the FERC a new cost allocation rule that will be used to determine who will pay the costs of upgrades to the regional transmission network once SMD has been implemented. VELCO has a number of network upgrades in the planning stage and the net cost to the Company of any such new investments will be affected by cost allocation rulings by the FERC.

At this time, the Company is unsure as to the outcome of these matters or the potential affects on the Company.

COMPETITION – RISK FACTORS

Utility If retail competition is implemented in Vermont or in Connecticut Valley's New Hampshire service territory, the Company is unable to predict the impact on its revenues, the Company's ability to retain existing customers with respect to their power supply purchases and attract new customers or the margins that will be realized on retail sales of electricity, if any such sales are sought. The Company expects its power distribution and transmission service to its customers to continue on an exclusive basis subject to continuing economic regulation.

Historically, electric utility rates in Vermont and New Hampshire have been based on a utility's costs. As a result, electric utilities are subject to certain accounting standards that are not applicable to other business enterprises. SFAS No. 71 requires regulated entities, in appropriate circumstances, to establish regulatory assets and liabilities, and thereby defer the income statement impact of certain costs and revenues that are expected to be realized in future rates.

The Company believes it currently complies with the provisions of SFAS No. 71 for both its regulated Vermont and New Hampshire service territories and FERC-regulated wholesale businesses. Also see Note 1 to the Consolidated Financial Statements and Critical Accounting Polices, above.

Interest Rate Risk As of December 31, 2002, the Company has $16.3 million of Industrial Development/Pollution Control bonds outstanding, of which $10.8 million have an interest rate that floats monthly and $5.5 million floats every five years with the short-term credit markets. All other utility debt has a fixed rate. There are no interest lock or swap agreements in place. The Company has $46.3 million of consolidated temporary cash investments as of December 31, 2002, including $24.8 million of non-utility temporary cash investments, of which $14.2 million is related to Catamount. Also see non-utility risk factors below. Interest rate changes could also affect calculations affecting estimated pension and other benefit liabilities, thereby affecting pension and other benefit expenses and potentially requiring contributions to the trusts.

Equity Market Risk As of December 31, 2002, the Company's pension trust holds marketable equity securities in the amount of $34.8 million and its share of the Millstone Unit #3 decommissioning trust, in the amount of $2.3 million. The Company also maintains a variety of insurance policies in a Rabbi Trust, with a current value in the amount of $4.2 million, as of December 31, 2002, to support various supplemental retirement and deferred compensation plans. The current values of certain of these policies are affected by changes in the equity market. Therefore, changes in the equity market could affect pension expense as well as the Millstone Unit #3 decommissioning fund and the Rabbi Trust asset balances.

Credit Risk The Company has $16.9 million of letters of credit, supporting three series of tax-exempt pollution control/industrial development bonds, totaling $16.3 million, of which the earliest series matures in 2009. These letters of credit expire on August 31, 2003 and need to be renewed. Without the support of the letters of credit, the bonds could become due.

The Company has $10.5 million of first mortgage bonds maturing in the next five years and $75 million of second mortgage bonds that mature on August 1, 2004. It is currently anticipated that all, or a majority of, the debt will be refinanced at maturity. The type, timing and terms of future financing that the Company may need will depend upon its cash needs, the availability of refinancing sources and the prevailing conditions in the financial markets.

The covenants covering the Company's second mortgage bonds contain limiting restrictions if those bonds receive a debt rating below BBB- from rating agencies. The current ratings of the bonds from both Fitch and Standard & Poor's are BBB- (stable). The limiting characteristics include certain restrictions on investments in non-regulated subsidiaries, the incurrence of indebtedness and the payment of dividends. Restrictions are dependent on meeting both a Fixed Charge Coverage and a Cumulative Cash Flow test. At December 31, 2002, both tests indicate current levels are acceptable.

Inflation The annual rate of inflation, as measured by the Consumer Price Index, was 1.6 percent for 2002, 2.8 percent for 2001 and 3.4 percent for 2000. The Company's revenues, however, are based on rate regulation that generally recognizes only historical costs. Inflation therefore continues to have an impact on most aspects of the business.

Non-Utility In 2001, Catamount undertook a comprehensive strategic review of its operations. As a result, Catamount has refocused its efforts from being an investor in late-stage renewable energy to being primarily focused on developing, owning and operating wind energy projects. Catamount's future success is dependent on the acceptance of wind power as an energy source by large producers, utilities, and other purchasers of electricity. Historically, the wind energy industry had a reputation for numerous problems relating to the failure of many wind-power generating facilities developed in the early 1980s to perform acceptably. In addition, many potential customers believe that wind energy is an unpredictable and inconsistent resource, is uneconomic compared to other sources of power and does not produce stable voltage and frequency. Although Catamount believes that these concerns may be adequately addressed in the near-term, there is no guarantee of wind power acceptance by potential customers as an energy source.

Dependence on Governmental Policies The wind energy industry is highly dependent upon governmental policies and laws enacted to stimulate growth of clean renewable energy through tax credits and other incentive plans, including mandatory purchasing requirements by local utilities of renewable energy, including wind energy. While the trend worldwide is to increase the use of renewable energy sources, there is no assurance that any particular governmental policy or tax credit or incentive program will be continued in any jurisdiction where Catamount conducts business.

United States The U.S. Congress has enacted a production tax credit, which provides owners of wind energy projects a credit of 1.8 cents/kWh produced by any wind energy project installed and in operation by December 31, 2003. This credit may be earned by such eligible projects for the first 10 years of each project's life. Continued growth of the U.S. wind energy industry depends upon this tax credit being extended beyond December 2003, and depends upon an adequate market of investors who can utilize this credit efficiently. While bills containing extensions for the production tax credit have been introduced in both houses of the U.S. Congress, there is no assurance that such bills will be enacted into law and that the tax credit will be so extended. There are currently 13 U.S. states that have some form of mandatory renewable energy purchase requirements by utilities located in their respective states. Several U.S. states have other incentive and grant programs to promote renewable energy. There is no assurance that any such program will be extended when each expires and there is no assurance that other states will follow the lead in promoting mandatory purchasing schemes.

Europe The European Union ("EU") Renewable Energy Directive, formally adopted in September 2001, establishes national targets that would collectively result in renewable energy contributing 12 percent of the gross electricity consumed by the EU's 15 member countries in 2010 and a long-term goal of 22 percent. There can be no assurances as to how EU countries will implement and maintain policies related to the Renewable Energy Directive. Further, revenues generated in Catamount's targeted European markets are expected to be derived from renewable energy electricity purchases, which are currently required by national law. Support for renewable energy could diminish in any or all of these countries, resulting in the repeal of these national laws.

Regulation in the United States The electric utility industry in the U.S. remains highly regulated and subject to energy and environmental laws at the federal, state and local levels. Catamount's operations are currently unregulated by the federal or state electric industry regulators, despite the fact Catamount is a wholly owned subsidiary of the Company. In addition, electric generation projects are subject to federal, state and local laws and administrative regulations, which govern the geographic location, zoning, land use and operation of plants and emissions produced by said plants. There is no guarantee that Catamount's operations will remain unregulated and may be subject to federal, state and local regulations in the future.

Reliance on Third-Party Equipment Vendors Currently less than 10 major wind turbine-generating ("WTG") manufacturers are serving the worldwide wind energy market. In the recent past, several of these manufacturers have been subject to financial difficulties, mergers and industry consolidation. Because customer demand for WTGs fluctuates based upon market conditions, there is no assurance that manufacturing capacity will be available to meet expected increases in demand at any one time. Further, there is no assurance that key components and parts will be available to service WTGs, which could adversely impact Catamount's operations.

Foreign Operations Catamount currently owns investments in the UK and Germany and intends on developing wind energy projects in targeted European countries. Catamount's business may be affected by fluctuations in currency exchange rates, governmental currency controls, changes in various regulatory requirements, political and economic changes and disruptions, difficulties in managing foreign operations, including collections, and possible adverse tax consequences.

Interest Rate Risk Catamount has a variable rate revolving credit/term loan facility. In January 2003, Catamount paid down its outstanding loan by $12.6 million, thereby reducing its exposure to interest rate risk. Catamount also maintains temporary cash investments to meet its liquidity needs. In December 2002, Catamount's temporary cash investments amounted to $14.9 million, which includes a portion used for the January 2003 paydown of its outstanding loan.

Credit Exposure Recent events including uncertainties concerning the operations of the wholesale markets and the demise of major wholesale power marketing companies have increased credit exposure in the energy industry and specifically with unregulated energy companies. Obtaining or renewing corporate credit facilities is challenging and there is no guarantee credit will either be extended or renewed. In December 2002, Catamount extended its corporate credit facility for an additional two years.

RECENT ACCOUNTING PRONOUNCEMENTS

Impairment or Disposal of Long-Lived Assets On January 1, 2002, the Company adopted SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144") that replaces SFAS No. 121, which the Company previously adopted. As with SFAS No. 121, SFAS No. 144 requires that any assets, including regulatory assets, that are no longer probable of recovery through future revenues, be revalued based upon undiscounted future cash flows. SFAS No. 144 requires that a rate-regulated enterprise recognize an impairment loss for the amount of costs excluded from recovery. As of December 31, 2002, based upon the regulatory environment within which the Company currently operates, SFAS No. 144 did not have an impact on the Company's regulated businesses. Competitive influences or regulatory developments may impact this status in the future.

Asset Retirement Obligations In August 2001, the Financial Accounting Standards Board ("FASB") approved the issuance of SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). This statement provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of long-lived assets and requires entities to record the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. The Company has retirement obligations associated with decommissioning related to its investments in nuclear plants, certain of its jointly owned generating plants and certain Catamount investments. The Company adopted SFAS No. 143 on January 1, 2003 as required. The cumulative effect of adopting SFAS No. 143 is not material.

Costs Associated with Exit or Disposal Activities In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* ("SFAS No. 146"), which requires entities to record a liability for costs related to exit or disposal activities when the costs are incurred. Previous accounting guidance required the liability to be recorded at the date of commitment to an exit or disposal plan. This statement applies only to exit activities initiated in 2003 and after. The Company does not expect a material impact on its financial position or results of operations.

Stock-Based Compensation Transition and Disclosure In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, ("SFAS No. 148") an amendment of SFAS No. 123. SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair-value-based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require more prominent and more frequent disclosures in financial statements about the effects of stock-based compensation. This statement is effective for financial statements for fiscal years ending after December 15, 2002. The Company adopted the disclosure requirements related to SFAS No. 148 as of December 31, 2002.

Selected Financial Data

(Dollars in thousands, except per share amounts)	2002	2001	2000	1999	1998
Operating revenues	**$303,389**	$302,476	$333,926	$419,815	$303,835
Net income before extraordinary charge	**$19,767**	$2,589	$18,043	$16,584	$3,983
Extraordinary charge net of taxes	-	$182	-	-	-
Net income	**$19,767**	$2,407	$18,043	$16,584	$3,983
Earnings available for common stock	**$18,239**	$711	$16,264	$14,722	$2,038
Consolidated return on average common stock equity	**9.6%**	0.4%	8.6%	7.9%	1.1%
Earnings per basic share of common stock before extraordinary charge	**$1.56**	$.08	$1.42	$1.28	$.18
Earnings per basic share of common stock	**$1.56**	$.06	$1.42	$1.28	$.18
Earnings per diluted share of common stock before extraordinary charge	**$1.53**	$.08	$1.41	$1.28	$.18
Earnings per diluted share of common stock	**$1.53**	$.06	$1.41	$1.28	$.18
Cash dividends paid per share of common stock	**$.88**	$.88	$.88	$.88	$.88
Book value per share of common stock	**$16.83**	$15.81	$16.57	$16.05	$15.63
Net cash provided by operating activities	**$42,570**	$30,216	$60,867	$31,232	$21,743
Dividends paid	**$12,222**	$11,433	$11,888	$11,950	$12,006
Construction and plant expenditures	**$14,442**	$16,553	$14,968	$13,231	$16,046
Conservation and load management expenditures	**$236**	$504	$1,136	$2,440	$2,208

At End of Year

Long-term debt (1)	**$137,908**	$159,771	$152,975	$155,251	$90,077
Capital lease obligations (1)	**$11,762**	$12,897	$13,978	$15,060	$16,141
Redeemable preferred stock (1)	**$10,000**	$15,000	$16,000	$17,000	$18,000
Total capitalization	**$365,332**	$379,236	$381,704	$379,386	$311,454
Total assets	**$526,865**	$521,674	$539,838	$563,959	$530,282

(1) Excluding current portion

Independent Auditor's Report

**To the Board of Directors of
Central Vermont Public Service Corporation:**

We have audited the accompanying consolidated balance sheet and statement of capitalization of Central Vermont Public Service Corporation and subsidiaries (the Company) as of December 31, 2002, and the related consolidated statements of income, changes in common stock equity and cash flows for the year then ended December 31, 2002. The financial statements of the Central Vermont Public Service 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 a matter paragraph on those financial statements in their report dated February 4, 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 Central Vermont Public Service 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.

As discussed in Note 12, the Company has reached agreement to sell Connecticut Valley Electric Company, its wholly owned subsidiary, to Public Service Company of New Hampshire. The Company believes this sale will render as moot a pending request filed with the Federal Energy Regulatory Commission for an exit fee mechanism to cover the stranded costs resulting from the potential cancellation of the power contract between the Company and Connecticut Valley Electric Company. If the sale is not completed and the power contract is ultimately cancelled, the Company would be required to recognize a loss under this contract of a material amount if it is unable to obtain an order authorizing the recovery of a significant portion of the exit fee, or other appropriate stranded cost mechanism.

Deloitte & Touche LLP

Deloitte & Touche, LLP
Boston, Massachusetts
February 4, 2003

The following Report of Independent Public Accountants is a copy of the previously issued Arthur Andersen, LLP report on Central Vermont Public Service Corporation. Arthur Andersen, LLP has not reissued this report.

Report of Independent Public Accountants

**To the Board of Directors of
Central Vermont Public Service Corporation:**

We have audited the accompanying consolidated balance sheets and statements of capitalization of Central Vermont Public Service Corporation and its wholly owned subsidiaries (the Company) as of December 31, 2001 and 2000, and the related consolidated statements of income, changes in common stock equity 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 financial statements referred to above present fairly, in all material respects, the financial position of Central Vermont Public Service Corporation and its wholly owned subsidiaries as of December 31, 2001 and 2000 and the results of their 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 12, the Company has filed with the Federal Energy Regulatory Commission a request for an exit fee mechanism to cover the stranded costs resulting from the potential cancellation of the power contract between the Company and its wholly owned subsidiary Connecticut Valley. If the power contract is ultimately cancelled and the Company is unable to obtain an order authorizing the recovery of a significant portion of the exit fee, or other appropriate stranded cost mechanism, the Company would be required to recognize a loss under this contract of a material amount.

Arthur Andersen LLP

Arthur Andersen, LLP
Boston, Massachusetts
February 4, 2002

Consolidated Statements of Income

(Dollars in thousands, except per share amounts)	Year Ended December 31 2002	2001	2000
Operating Revenues	**$303,389**	$302,476	$333,926
Operating Expenses			
Operation			
Purchased power	**146,765**	147,662	185,941
Production and transmission	**25,495**	24,489	26,294
Other operation	**44,050**	43,420	44,119
Maintenance	**17,678**	18,264	14,813
Depreciation	**16,911**	17,041	16,882
Other taxes, principally property taxes	**13,307**	12,739	12,264
Taxes on income	**12,234**	11,472	9,034
Total operating expenses	**276,440**	275,087	309,347
Operating Income	**26,949**	27,389	24,579
Other Income and Deductions			
Equity in earnings of affiliates	**3,909**	2,669	3,268
Allowance for equity funds during construction	**71**	59	69
Other income, net	**1,441**	(16,614)	7,342
(Provision) benefit for income taxes	**(90)**	2,964	(2,777)
Total other income and deductions, net	**5,331**	(10,922)	7,902
Total Operating and Other Income	**32,280**	16,467	32,481
Interest Expense			
Interest on long-term debt	**12,548**	12,890	14,075
Other interest	**(1)**	1,018	404
Allowance for borrowed funds during construction	**(34)**	(30)	(41)
Total interest expense, net	**12,513**	13,878	14,438
Net Income Before Extraordinary Charge	**19,767**	2,589	18,043
Extraordinary loss (net of tax benefit of $124,000 in 2001)	-	182	-
Net Income	**19,767**	2,407	18,043
Preferred Stock Dividends Requirements	**1,528**	1,696	1,779
Earnings Available For Common Stock	**$18,239**	$711	$16,264
Earnings Per Share of Common Stock – Basic:			
Earnings before extraordinary charge	**$1.56**	$0.08	$1.42
Extraordinary charge	-	0.02	-
Earnings Per Share of Common Stock - Basic	**$1.56**	$0.06	$1.42
Average Shares of Common Stock Outstanding - Basic	**11,678,239**	11,551,042	11,488,351
Earnings Per Share of Common Stock – Diluted:			
Earnings before extraordinary charge	**$1.53**	$0.08	$1.41
Extraordinary charge	-	0.02	-
Earnings Per Share of Common Stock - Diluted	**$1.53**	$0.06	$1.41
Average Shares of Common Stock Outstanding - Diluted	**11,942,822**	11,780,235	11,531,890
Dividends Paid Per Share of Common Stock	**$0.88**	$0.88	$0.88

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

Consolidated Statements of Cash Flows

(Dollars in thousands)	Year Ended December 31 2002	2001	2000
Cash Flows Provided (Used) By:			
Operating Activities			
Net income	**$19,767**	$2,407	$18,043
Adjustments to reconcile net income to net cash provided by operating activities			
Extraordinary charge	**-**	182	-
Equity in earnings of affiliates	**(3,909)**	(2,669)	(3,268)
Dividends received from affiliates	**4,040**	2,773	4,315
Equity in earnings from non-utility investments	**(11,603)**	(6,079)	(1,223)
Distribution of earnings from non-utility investments	**10,639**	4,636	4,457
Depreciation	**16,911**	17,041	16,882
Regulatory asset write-off	**-**	9,000	-
Asset impairment charges (including tax valuation allowance)	**2,774**	8,905	1,000
Investment write-down	**-**	1,963	-
Amortization of capital leases	**1,143**	1,089	1,089
Deferred income taxes and investment tax credits	**3,229**	(5,083)	(3,861)
Net (deferral) and amortization of nuclear replacement energy and maintenance costs	**3,683**	(2,517)	6,207
Amortization of conservation and load management costs	**2,217**	3,144	5,339
Net (deferral) and amortization of restructuring costs	**59**	(1,328)	115
Decrease in accounts receivable and unbilled revenues	**781**	4,746	15,754
Increase (decrease) in accounts payable	**598**	(3,712)	(6,597)
Increase (decrease) in accrued income taxes	**877**	(1,614)	753
Change in other working capital items	**4,137**	(6,532)	3,029
Change in environmental reserve	**(1,844)**	(285)	(275)
Deferred Vermont Yankee fuel rod costs	**(3,854)**	-	-
Deferred Vermont Yankee sale costs	**(8,197)**	-	-
Other, net	**1,122**	4,149	(892)
Net cash provided by operating activities	**42,570**	30,216	60,867
Investing Activities			
Construction and plant expenditures	**(14,442)**	(16,553)	(14,968)
Conservation and load management expenditures	**(236)**	(504)	(1,136)
Return of capital	**336**	641	488
Proceeds from sale of non-utility assets	**13,335**	-	-
Non-utility investments	**(253)**	(13,671)	(4,634)
Utility investments	**(449)**	-	-
Other investments, net	**(258)**	(474)	(134)
Net cash used for investing activities	**(1,967)**	(30,561)	(20,384)
Financing Activities			
Sale of treasury stock	**416**	556	534
Proceeds from dividend reinvestment program	**1,309**	-	-
Short-term debt - net	**-**	-	17
Long-term debt - net	**(8,208)**	9,796	(14,776)
Retirement of preferred stock	**(6,000)**	-	(1,000)
Common and preferred dividends paid	**(12,222)**	(11,433)	(11,888)
Reduction in capital lease obligations	**(1,143)**	(1,089)	(1,089)
Other	**-**	20	244
Net cash used for financing activities	**(25,848)**	(2,150)	(27,958)
Effect of Exchange Rate Changes on Cash	**118**	-	-
Net Increase (Decrease) In Cash and Cash Equivalents	**14,873**	(2,495)	12,525
Cash and Cash Equivalents at Beginning of Year	**45,491**	47,986	35,461
Cash and Cash Equivalents at End of Year	**$60,364**	$45,491	$47,986
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$12,657**	$13,871	$13,862
Income taxes (net of refunds)	**$10,773**	$16,892	$15,118
Non-cash Operating, Investing and Financing Activities			
Stock award plans (Note 6)			
Regulatory assets (Notes 1, 2 and 12)			
Long-term lease arrangements (Note 13)			

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

Consolidated Balance Sheets

(Dollars in thousands)	December 31 2002	2001
ASSETS		
Utility Plant, at original cost	**$501,963**	$490,137
Less accumulated depreciation	**207,781**	198,087
	294,182	292,050
Construction work-in-progress	**9,307**	15,727
Nuclear fuel, net	**1,130**	852
Net utility plant	**304,619**	308,629
Investments and Other Assets		
Investments in affiliates	**23,716**	23,823
Non-utility investments	**35,087**	49,543
Non-utility property, less accumulated depreciation	**2,224**	2,401
Total investments and other assets	**61,027**	75,767
Current Assets		
Cash and cash equivalents	**60,364**	45,491
Special deposits	**-**	7
Accounts receivable, less allowance for uncollectible accounts ($1,303 in 2002 and $2,071 in 2001)	**21,708**	21,951
Unbilled revenues	**15,985**	16,404
Materials and supplies, at average cost	**3,341**	4,167
Prepayments	**2,375**	3,676
Other current assets	**4,619**	5,408
Total current assets	**108,392**	97,104
Regulatory Assets	**22,784**	32,403
Other Deferred Charges	**30,043**	7,771
Total Assets	**$526,865**	$521,674
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock equity	**$197,608**	$183,514
Preferred and preference stock	**8,054**	8,054
Preferred stock with sinking fund requirements	**10,000**	15,000
Long-term debt	**137,908**	159,771
Capital lease obligations	**11,762**	12,897
Total capitalization	**365,332**	379,236
Current Liabilities		
Current portion of preferred stock	**-**	1,000
Current portion of long-term debt	**20,879**	7,225
Accounts payable	**5,572**	4,796
Accounts payable – affiliates	**11,587**	12,092
Accrued income taxes	**951**	74
Dividends declared	**-**	2,978
Nuclear decommissioning costs	**3,263**	2,298
Other current liabilities	**20,319**	19,739
Total current liabilities	**62,571**	50,202
Deferred Credits		
Deferred income taxes	**41,766**	38,828
Deferred investment tax credits	**5,267**	5,658
Nuclear decommissioning costs	**20,899**	12,826
Other deferred credits	**31,030**	34,924
Total deferred credits	**98,962**	92,236
Commitments and Contingencies		
Total Capitalization and Liabilities	**$526,865**	$521,674

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

Consolidated Statements of Capitalization

(Dollars in thousands)	December 31 2002	2001
Common Stock Equity		
Common stock, $6 par value, authorized 19,000,000 shares; issued 11,807,495 shares	**$70,845**	$70,715
Other paid-in capital	**48,434**	47,634
Accumulated other comprehensive income (loss), net of tax	**150**	(623)
Deferred compensation plans - employee stock ownership plans	**(1,041)**	(1,097)
Treasury stock (64,854 shares and 175,165 shares, respectively, at cost)	**(857)**	(2,285)
Retained earnings	**80,077**	69,170
Total common stock equity	**197,608**	183,514
Cumulative Preferred and Preference Stock		
Preferred stock, $100 par value, authorized 500,000 shares		
Outstanding:		
Non-redeemable		
4.15% Series; 37,856 shares	**3,786**	3,786
4.65% Series; 10,000 shares	**1,000**	1,000
4.75% Series; 17,682 shares	**1,768**	1,768
5.375% Series; 15,000 shares	**1,500**	1,500
Redeemable		
8.30% Series; 100,000 shares	**10,000**	16,000
Preferred stock, $25 par value, authorized 1,000,000 shares		
Outstanding - none	**-**	-
Preference stock, $1 par value, authorized 1,000,000 shares		
Outstanding - none	**-**	-
	18,054	24,054
Less current portion	**-**	1,000
Total cumulative preferred and preference stock	**18,054**	23,054
Long-Term Debt		
First Mortgage Bonds		
9.26% Series GG, due 2002	**-**	3,000
9.97% Series HH, due 2003	**3,000**	7,000
8.91% Series JJ, due 2031	**15,000**	15,000
6.01% Series MM, due 2003	**7,500**	7,500
6.27% Series NN, due 2008	**3,000**	3,000
6.90% Series OO, due 2023	**17,500**	17,500
Second Mortgage Bonds		
8.125%, due 2004	**75,000**	75,000
Vermont Industrial Development Authority Bonds		
Variable, due 2013 (1.35% at December 31, 2002)	**5,800**	5,800
New Hampshire Industrial Development Authority Bonds		
5.50%, due 2009	**5,450**	5,500
Connecticut Development Authority Bonds		
Variable, due 2015 (1.30% at December 31, 2002)	**5,000**	5,000
Other, various	**21,537**	22,696
	158,787	166,996
Less current portion	**20,879**	7,225
Total long-term debt	**137,908**	159,771
Capital Lease Obligations	**11,762**	12,897
Total Capitalization	**$365,332**	$379,236

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

Consolidated Statements of Changes in Common Stock Equity

(Dollars in thousands)	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Deferred Compensation Plan – Employee Stock	Accumulated Other Comprehensive Income	Treasury Stock	Retained Earnings	Total
Balance, December 31, 1999	11,466,805	$70,715	$45,340	-	$(246)	$(4,159)	$72,371	$184,021
Treasury stock at cost	41,175					535		535
Issuance of Treasury stock for option plans							(93)	(93)
Net income							18,043	18,043
Other comprehensive income net of taxes					(23)			(23)
Allocation of benefits – employee stock				$233				233
Unearned stock compensation			448	(591)				(143)
Cash dividends on capital stock:								
Common stock – $.88 per share							(10,118)	(10,118)
Cumulative preferred stock:								
Non-redeemable							(369)	(369)
Redeemable							(1,411)	(1,411)
Amortization of preferred stock issuance expenses			22					22
Balance, December 31, 2000	11,507,980	$70,715	$45,810	$(358)	$(269)	$(3,624)	$78,423	$190,697
Treasury stock at cost	102,703					1,339		1,339
Issuance of Treasury stock for option plans							(41)	(41)
Net income							2,407	2,407
Other comprehensive income net of taxes					(354)			(354)
Allocation of benefits – employee stock				1,074				1,074
Unearned stock compensation			1,802	(1,813)				(11)
Cash dividends on capital stock:								
Common stock – $.88 per share							(10,183)	(10,183)
Cumulative preferred stock:								
Non-redeemable							(368)	(368)
Redeemable							(1,328)	(1,328)
Amortization of preferred stock issuance expenses			22					22
Other adjustments							260	260
Balance, December 31, 2001	11,610,683	$70,715	$47,634	$(1,097)	$(623)	$(2,285)	$69,170	$183,514
Treasury stock at cost	131,958					1,428		1,428
Issuance of Treasury stock for option plans							384	384
Net income							19,767	19,767
Other comprehensive income net of taxes					773			773
Allocation of benefits – employee stock				1,065				1,065
Unearned stock compensation			480	(1,009)				(529)
Cash dividends on capital stock:								
Common stock – $.88 per share							(7,716)	(7,716)
Cumulative preferred stock:								
Non-redeemable							(594)	(594)
Redeemable							(934)	(934)
Amortization of preferred stock issuance expenses			39					39
Premium on capital stock			257					257
Dividend reinvestment plan		130						130
Other adjustments			24					24
Balance, December 31, 2002	**11,742,641**	**$70,845**	**$48,434**	**$(1,041)**	**$150**	**$(857)**	**$80,077**	**$197,608**

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

Notes to Consolidated Financial Statements

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

About Central Vermont Public Service Corporation Central Vermont Public Service Corporation ("the Company") is an independent energy and utility business based in Vermont. The Company distributes, transmits and markets electricity and invests in renewable and independent-power generation projects. The Company's wholly owned subsidiaries include Connecticut Valley Electric Company ("Connecticut Valley"), which distributes and sells electricity in parts of New Hampshire; Catamount Energy Corporation ("Catamount"), which invests primarily in wind energy projects in the United States and Western Europe; and Eversant Corporation ("Eversant"), which operates a rental water heater business through its subsidiary, SmartEnergy Water Heating Services, Inc.

Consolidation Policy and Use of Estimates The consolidated financial statements include the accounts of the Company and its subsidiaries in which it has a controlling interest. Intercompany transactions have been eliminated in consolidation.

Investments in entities over which the Company does not maintain a controlling financial interest are accounted for using the equity method when the Company has the ability to exercise significant influence over its operation. Under this method, the Company records its ownership share of the net income or loss of each investment in the accompanying consolidated financial statements.

The Company's ownership interests in jointly owned generating and transmission facilities are accounted for on a pro rata basis using the Company's ownership percentages and are recorded in the Company's Consolidated Balance Sheets. The Company's share of operating expenses for these facilities is included in the corresponding operating accounts on the Consolidated Statements of Income.

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosures of contingent assets and liabilities and revenues and expenses. Actual results could differ from those estimates. In addition, the Company and its subsidiaries are subject to the accounting and reporting requirements of the Securities and Exchange Commission ("SEC").

Utility Regulation The Company is subject to regulation by the Vermont Public Service Board ("PSB"), the New Hampshire Public Utilities Commission ("NHPUC") and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting and other matters pertaining to regulated operations. As such, the Company currently prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), for its regulated Vermont service territory, FERC-regulated wholesale business and Connecticut Valley's New Hampshire service territory. In order for a company to report under SFAS No. 71, the company's rates must be designed to recover its costs of providing service and the company must be able to collect those rates from customers. If rate recovery of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, this accounting standard would no longer apply to the Company's regulated operations. In the event the Company determines that it no longer meets the criteria for applying SFAS No. 71, the accounting impact would be an extraordinary non-cash charge to operations of an amount that could be material unless stranded cost recovery is allowed through a rate mechanism. Criteria that could give rise to the discontinuance of SFAS No. 71 include 1) increasing competition that restricts the Company's ability to establish prices to recover specific costs, and 2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. Management periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, Management believes future recovery of its regulatory assets in the State of Vermont and the State of New Hampshire for the Company's retail and wholesale businesses is probable.

Unregulated Business Results of operations of Catamount and Eversant are included in Other income, net in the Other Income and Deductions section of the Consolidated Statements of Income. Catamount's policy is to expense all screening, feasibility and development expenditures associated with investments in new projects. Catamount's project costs incurred subsequent to obtaining financial viability are recognized as assets subject to depreciation or amortization. Project viability is obtained when it becomes probable that costs incurred will generate future economic benefits sufficient to recover these costs.

In the third quarter of 2002, Catamount recorded asset impairment charges of $2.8 million, related to the pending sale of certain of its investments in non-regulated energy generation projects. In the fourth quarter of 2002, Catamount sold two of its investments and has another investment under agreement for sale. Previously, in the fourth quarter of 2001, Catamount recorded asset impairment charges related to four of its investments in non-regulated energy generation projects. See Note 3 – Non-Utility Investments.

Revenues Revenues related to the sale of electricity are generally recorded when service is rendered or when electricity is distributed to customers. Electricity sales to individual customers are based on the monthly reading of their meters. Estimated unbilled revenues are recorded at the end of each monthly accounting period. The Company follows the accrual method of accounting for revenues, recognizing revenue for kilowatt-hours that have been delivered but not yet billed through the end of the monthly accounting period. The determination of unbilled revenues requires the Company to make various estimates including 1) energy generated, purchased and resold, 2) losses of energy over transmission and distribution lines, 3) kilowatt-hour usage by retail customer mix-residential, commercial and industrial, and 4) average retail customer pricing rates. Unbilled revenues as of December 31, 2002, 2001 and 2000 were $16 million, $16.4 million and $17.1 million, respectively.

Purchased Power The Company records the annual cost of power obtained under long-term contracts as operating expenses. Since these contracts do not convey to the Company the right to use the related property, plant or equipment, they are considered executory in nature. This accounting treatment is in contrast to the Company's commitment with respect to the Hydro-Quebec Phase I and II transmission facilities, which are considered capital leases. See Note 13 – Commitments and Contingencies.

Utility Plant Utility plant is recorded at original cost. Replacements of retirement units of property are charged to utility plant. Maintenance and repairs, including replacements not qualifying as retirement units of property, are charged to maintenance expense. The original cost of units retired, net of salvage value, and related costs of removal are charged to accumulated provision for depreciation. The primary components of utility plant include (dollars in thousands):

	December 31 2002	2001
Electric – transmission and distribution	**$378,295**	$364,211
Jointly owned generation and transmission units	**109,110**	108,941
Property under capital leases	**12,887**	14,030
Completed construction	**1,628**	2,912
Held for future use	**43**	43
Utility Plant, at original cost	**$501,963**	$490,137

Depreciation The Company uses the straight-line remaining life method of depreciation. Total depreciation expense was 3.33 percent, 3.53 percent and 3.57 percent of the cost of depreciable utility plant for the years 2002 through 2000, respectively.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), the Company recognizes tax assets and liabilities 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 ratably to income over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized.

Allowance for Funds Used During Construction Allowance for funds used during construction ("AFUDC") is the cost during the period of construction of debt and equity funds used to finance construction projects. The Company capitalizes AFUDC as part of the cost of major utility plant projects to the extent that costs applicable to such construction work in progress have not been included in rate base in connection with ratemaking proceedings. AFUDC equity represents a current non-cash credit to earnings, recoverable over the life of the property. The AFUDC rates used by the Company were 9.3 percent, 9.4 percent and 9.3 percent for the years 2002 through 2000, respectively.

Regulatory Accounting Under SFAS No. 71 the Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit incurred costs, typically treated as expense by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. In the event that the Company no longer meets the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, the Company would be required to write off related regulatory assets, certain other deferred charges and regulatory liabilities as summarized in the following table (dollars in thousands):

	December 31	
	2002	2001
Regulatory assets		
Conservation and load management (a)	**$1,853**	$4,633
Restructuring costs	**66**	59
Nuclear refueling outage costs (a)	**762**	4,445
Income taxes (b)	**6,087**	6,770
Dismantling costs (c):		
Maine Yankee nuclear power plant	**8,959**	10,612
Connecticut Yankee nuclear power plant	**3,774**	4,513
Unrecovered plant and regulatory study costs	**1,099**	1,310
Other regulatory assets	**184**	61
Subtotal Regulatory assets	**22,784**	32,403
Other deferred charges		
Vermont Yankee fuel rod maintenance deferral	**3,854**	-
Vermont Yankee sale costs	**8,197**	-
Yankee Atomic incremental dismantling costs (c)	**7,872**	-
Connecticut Yankee incremental dismantling costs (c)	**3,558**	-
Hydro-Quebec Sellback #3 derivative	**666**	1,038
Subtotal Other deferred charges	**24,147**	1,038
Other deferred credits		
Hydro-Quebec ice storm settlement	**8**	1,607
Excess over allowed rate of return cap - 2002	**681**	-
Other regulatory liabilities	**592**	620
Subtotal Other deferred credits	**1,281**	2,227
Net Regulatory Assets	**$45,650**	$31,214

(a) The Company earns a return on unamortized Conservation and Load Management costs and replacement energy and maintenance costs related to scheduled nuclear refueling outages.

(b) The net regulatory asset related to the adoption of SFAS No. 109 is recovered through tax expense in the Company's cost of service generally over the remaining lives of the related property.

(c) Recovery for the unamortized dismantling costs for Connecticut Yankee and Maine Yankee is provided without a return on investment through 2007 and 2008, respectively. Other deferred charges related to dismantling costs for these facilities are not currently included for recovery in rates.

Deferred Charges In a manner consistent with expected ratemaking treatment, the Company defers and amortizes certain items to reflect more accurately its costs of service. The Vermont Yankee-related deferred charges shown as Other deferred charges in the table above are based on Accounting Orders approved by the PSB that authorize the Company to defer such costs for recovery in future rates. Other deferred charges related to Yankee Atomic and Connecticut Yankee incremental dismantling costs are explained in more detail in Note 2 – Investments in Affiliates. The Hydro-Quebec Sellback #3 derivative is based on an Accounting Order approved by the PSB that allows for the contract's fair value to be recorded on the balance sheet as either a deferred asset or liability.

Other deferred charges of approximately $5.9 million, excluding those shown in the table above, include costs associated with hydro relicensing and various other deferred charges.

Deferred Credits Deferred Credits, excluding those shown in the table above, amount to $29.7 million and include environmental reserves, accruals for employee pension and other benefits, regulatory tax liabilities, reserves for damage claims and other various deferrals. The deferred credits of $1.3 million shown in the table above represent regulatory liabilities including excess earnings over the Vermont utility's allowed rate of return in 2002 and other costs that have been recovered by the Company but have not yet been included in rates. In the past, these costs have been applied against regulatory assets as agreed to with the Vermont Department of Public Service ("DPS") and approved by the PSB. See Note 12 – Retail Rates.

Miscellaneous Current Liabilities The Company's miscellaneous current liabilities at December 31, 2002 and 2001 include the following (dollars in thousands):

	2002	2001
Accrued employee costs - payroll and medical	**$5,186**	$3,774
Accrued interest	**2,984**	3,128
Other taxes	**2,288**	2,300
Deferred compensation	**2,579**	2,720
Customer deposits, interest and prepaid	**1,293**	1,328
Obligation under capital leases	**1,094**	1,094
Environmental and accident reserves	**897**	1,013
Accrued joint owned expenses and EEU	**963**	633
Miscellaneous accruals	**3,035**	3,749
Total	**$20,319**	$19,739

Valuation of Long-Lived Assets The Company periodically evaluates the carrying value of long-lived assets and long-lived assets to be disposed of, including its investments in nuclear generating companies, its unregulated investments, and its interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. See Note 3 – Non-Utility Investments for further discussion of impairment of non-utility investments.

Earnings Per Share Basic earnings per share is calculated by dividing net income by the weighted-average number of common shares outstanding for the period. Basic earnings per share represents the amount of earnings for the period available to each share of common stock outstanding for the periods presented. Diluted earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period calculated based on the weighted-average number of shares outstanding plus each share that would have been outstanding assuming the issuance of common shares for all dilutive potential common shares outstanding during the period.

Stock Options The Company accounts for its stock option plans under Accounting Principles Board Opinion No. 25 ("APB 25"), *Accounting for Stock Issued to Employees*, and related Interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, to stock-based employee compensation (dollars in thousands, except per share amounts):

	December 31		
	2002	2001	2000
Net Income, as reported	**$19,767**	$2,407	$18,043
Deduct: Total stock-based employee compensation expense*	**150**	118	84
Pro forma net income	**$19,617**	$2,289	$17,959
Earnings per share:			
Basic - as reported	**$1.56**	$.06	$1.42
Basic - pro forma	**$1.55**	$.05	$1.41
Diluted - as reported	**$1.53**	$.06	$1.42
Diluted - pro forma	**$1.51**	$.05	$1.41

* Fair value based method for all awards, net of related tax effects.

Environmental Liabilities The Company is engaged in various operations and activities that subject it to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. The Company's policy is to accrue a liability for those sites where costs for remediation, monitoring and other future activities are probable and can be reasonably estimated. See Note 13 - Commitments and Contingencies.

Derivative Financial Instruments On January 1, 2001, the Company adopted the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted (collectively "SFAS No. 133"). SFAS No. 133 requires that derivatives be recorded on the Consolidated Balance Sheets at fair value. The adoption of SFAS No. 133 did not have a material impact on the Company. The Company has a long-term purchased power contract that allows the seller to purchase specified amounts of power with advance notice (Hydro-Quebec Sellback #3). This contract has been determined to be a derivative under SFAS No. 133. At December 31, 2002, this derivative had an estimated fair value of approximately a $0.7 million unrealized loss, which is included in Other deferred credits on the Consolidated Balance Sheet along with an offsetting deferred asset, which is included in Other deferred charges. The estimated fair value is based on quoted market information where available and appropriate modeling methodologies.

Concentration of Credit Risk Financial instruments, which potentially expose the Company to concentrations of credit risk, consist primarily of cash, cash equivalents, restricted cash and accounts receivable. The Company maintains a significant portion of its cash and cash equivalent balances with several major financial institutions. As of December 31, 2002, approximately 6 percent of the Company's accounts receivable are concentrated with entities engaged in the energy industry. These industry concentrations could impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables are generally not collateralized; however, the Company believes the credit risk posed by industry concentration is offset by the diversification and creditworthiness of its customer base of residential, commercial and industrial customers.

Foreign Currency Translation All foreign non-utility assets and liabilities are translated at the year-end currency exchange rate. Revenues and expenses are translated at average exchange rates in effect during the year. Realized gains or losses from foreign currency translations are included in earnings of the current period.

Cash and Cash Equivalents The Company considers all highly liquid investments with an original maturity of three months or less when acquired to be cash equivalents. Cash and cash equivalents include restricted cash of $12.6 million from after-tax proceeds related to Catamount's investment sales in the fourth quarter of 2002, which were restricted under the revolving credit/term loan facility for payment against its outstanding term loan.

Reclassifications *The Company will record reclassifications to the* financial statements of the prior year when considered necessary or to conform to current year presentation.

Recent Accounting Pronouncements

Impairment or Disposal of Long-Lived Assets On January 1, 2002, the Company adopted SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144") that replaces SFAS No. 121, which the Company previously adopted. As with SFAS No. 121, SFAS No. 144 requires that any assets, including regulatory assets, that are no longer probable of recovery through future revenues, be revalued based upon undiscounted future cash flows. SFAS No. 144 requires that a rate-regulated enterprise recognize an impairment loss for the amount of costs excluded from recovery. As of December 31, 2002, based upon the regulatory environment within which the Company currently operates, SFAS No. 144 did not have an impact on the Company's regulated businesses. Competitive influences or regulatory developments may impact this status in the future.

Asset Retirement Obligations In August 2001, the Financial Accounting Standards Board ("FASB") approved the issuance of SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). This statement provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of long-lived assets and requires entities to record the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. The Company has retirement obligations associated with decommissioning related to its investments in nuclear plants, certain of its jointly owned generating plants and certain Catamount investments. The Company adopted SFAS No. 143 on January 1, 2003 as required. The cumulative effect of adopting SFAS No. 143 is not material.

Costs Associated with Exit or Disposal Activities In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* ("SFAS No. 146"), which requires entities to record a liability for costs related to exit or disposal activities when the costs are incurred. Previous accounting guidance required the liability to be recorded at the date of commitment to an exit or disposal plan. This statement applies only to exit activities initiated in 2003 and after. The Company does not expect a material impact on its financial position or results of operations.

Stock-Based Compensation Transition and Disclosure In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, ("SFAS No. 148") an amendment of SFAS No. 123. SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require more prominent and more frequent disclosures in financial statements about the effects of stock-based compensation. This statement is effective for financial statements for fiscal years ending after December 15, 2002. The Company adopted the disclosure requirements related to SFAS No. 148 as of December 31, 2002.

NOTE 2 – INVESTMENTS IN AFFILIATES

The Company's equity method investments are as follows (dollars in thousands):

	Ownership	December 31 2002	2001
Vermont Yankee Nuclear Power Corporation (1)	33.23%	$16,900	$16,818
Nuclear generating companies:			
Connecticut Yankee Atomic Power Company	2.0%	1,148	1,349
Maine Yankee Atomic Power Company	2.0%	1,052	1,257
Yankee Atomic Electric Company	3.5%	35	28
Vermont Electric Power Company, Inc. (2)			
Common stock	50.6%	4,079	3,710
Preferred stock	46.6%	502	661
		$23,716	$23,823

(1) In the first quarter of 2002 the Company's ownership percentage changed from 31.3 percent to 33.23 percent. On July 31, 2002, the Vermont Yankee plant was sold, however the Company has a 33.23 percent equity interest in the remaining corporation. See discussion below for more detail related to the Company's ownership in Vermont Yankee.

(2) In the third quarter of 2002, the Company's common stock ownership percentage in VELCO changed from 56.8 percent to 50.6 percent, as a result of other owners acquiring additional shares of VELCO's Class C common stock.

Vermont Yankee Summarized financial information for Vermont Yankee Nuclear Power Corporation ("VYNPC") is as follows (dollars in thousands):

Earnings	December 31 2002	2001	2000
Operating revenues	**$175,722**	$178,840	$178,294
Operating income	**$6,949**	$11,983	$16,144
Net income	**$9,454**	$6,119	$6,583
Company's equity in net income	**$3,141**	$1,912	$2,052

Investment	December 31 2002	2001
Current assets	**$73,794**	$35,344
Non-current assets	**131,088**	688,471
Total Assets	**204,882**	723,815
Less:		
Current liabilities	**22,724**	64,082
Non-current liabilities	**130,956**	605,558
Net assets	**$51,202**	$54,175
Company's equity in net assets	**$16,900**	$16,818

Vermont Yankee's revenues include sales to the Company of $60.2 million, $56.1 million, $55.5 million for 2002, 2001 and 2000, respectively. These amounts are reflected as purchased power, net of deferrals and amortization, in the Company's Consolidated Statements of Income.

Vermont Yankee had a 12-day mid-cycle outage starting May 11, 2002 in order to repair defective fuel rods. The Company's cost for the repair, including incremental capacity and replacement energy costs, was approximately $3.9 million. The Company received an Accounting Order from the PSB, allowing it to defer the additional costs related to the mid-cycle outage and Management believes that such amounts are probable of future recovery.

In October 2002, Vermont Yankee accomplished a 21-day refueling outage. Although the Company is no longer responsible for refueling outage costs, it remains responsible for procuring replacement energy during the outage and any other Vermont Yankee outages in the future. As such, the Company no longer defers or amortizes incremental capacity and replacement energy costs as it had done in the past. Under a purchased power agreement, the Company pays only for generation at scheduled annual fixed rates. Accordingly, as a result of the sale, the Company no longer bears the operating costs and risks associated with running the plant or the costs and risks associated with the eventual decommissioning of the plant.

Vermont Yankee Sale On August 15, 2001, Vermont Yankee reached an agreement to sell its nuclear power plant to Entergy Nuclear Vermont Yankee, LLC ("Entergy") for approximately $180 million, representing $145 million for the plant and related assets and $35 million for nuclear fuel. Under the agreement, Entergy assumes decommissioning liability for the plant and its decommissioning trust fund. The agreement also includes a purchased power contract ("PPA") with prices that generally range from 3.9 cents to 4.5 cents per kilowatt-hour through 2012. The PPA is subject to a "low-market adjuster" effective November 2005, that protects the current Vermont Yankee owner-utilities, including the Company and its power consumers, in the event power market prices drop significantly. If the market prices rise, however, the contract prices are not adjusted upward.

In January 2002, Vermont Yankee reached an agreement with the secondary purchasers and repurchased the shares held by the minority stockholders. Both parties had previously intervened in the sale proceedings; the secondary purchasers were seeking adjustments in their power purchase contracts and the minority stockholders were asserting dissenters' rights. On January 1, 2002, as a result of the repurchased shares, the Company's ownership percentage of Vermont Yankee changed from 31.3 percent to 33.23 percent.

On March 6, 2002, the Company, Green Mountain Power ("GMP"), Vermont Yankee, Entergy and the Vermont Department of Public Service ("DPS") filed a joint Memorandum of Understanding ("MOU") that resolved all issues raised by the DPS earlier in the proceeding and recommended approval of the sale in accordance with the terms of the MOU. The intervenors did not join in the MOU. During April and May 2002 the Vermont Public Service Board ("PSB") held several hearings related to the sale proceedings and MOU.

The Nuclear Regulatory Commission ("NRC") approved the transfer of the Vermont Yankee operating license to Entergy in May 2002; the FERC had approved the sale at the end of January 2002.

On June 13, 2002, the PSB issued an Order approving the Vermont Yankee sale to Entergy, along with the associated power purchase agreement between the current owners and Entergy. In approving the transactions, the PSB largely accepted the terms of the MOU reached between the current owners, Entergy and the DPS, however the PSB set several conditions including:

- requiring that any money remaining in the decommissioning fund following completion of decommissioning be returned to consumers;
- requiring that the Company and GMP submit plans for using their share of any excess remaining in the decommissioning fund toward the development and use of renewable resources for Vermont;
- significant financial guarantees and corporate commitments from Entergy's parent corporation, ensuring the reliability of its subsidiaries' commitments;
- requiring the Company to file an updated cost-of-service and appropriate additional information as necessary in April 2003 to determine whether a rate decrease is appropriate in 2003 or 2004; and
- prohibiting Entergy from operating Vermont Yankee after March 31, 2012 without prior approval of the PSB.

On June 21, 2002, Entergy filed a Motion to Alter or Amend the PSB's June 13, 2002 Order to accept the agreement between the Vermont Yankee owners and the DPS as written and allow the 50-50 sharing with ratepayers of any excess remaining in Vermont Yankee's decommissioning trust fund after the decommissioning is completed after 2022. On July 1, 2002, the DPS issued a response to the PSB's Order requesting that the PSB reconsider its ruling and recommended that any excess decommissioning funds be split between ratepayers and Entergy. On July 11, 2002, the PSB rendered a decision on Entergy's Motion in which the PSB confirmed its June 13, 2002 Order.

On July 22, 2002, Entergy and the utility owners of Vermont Yankee reached agreements that enabled the sale to close by July 31, 2002. Under the terms of the agreements, Vermont ratepayers will receive 100 percent of the Vermont utilities' share of any surplus remaining in the decommissioning fund when the plant is decommissioned. The non-Vermont owners, representing 45 percent ownership of the plant, restored the substance of the original agreement by assigning 100 percent of their excess decommissioning funds to Entergy. The Company agreed to pay approximately $1 million in stockholder funds to the non-Vermont utility owners of the plant to provide parity for assigning their share of the decommissioning fund to Entergy.

The Securities and Exchange Commission approved the sale on July 30, 2002 and on July 31, 2002, Vermont Yankee completed the sale of its assets to Entergy. At that time Entergy assumed the decommissioning liability for the plant and its decommissioning trust fund. The Company has a 33.23 percent equity interest in VYNPC, which will continue as a Vermont-based corporation and will administer the purchased power contracts among the former plant owners and Entergy. The Company receives its 35 percent entitlement of Vermont Yankee output sold by Entergy to VYNPC and one remaining secondary purchaser will continue receiving a small percentage of the Company's entitlement. Under the PPA between Entergy and VYNPC, VYNPC pays Entergy only for generation at fixed rates; VYNPC in turn includes the PPA charges from Entergy with certain residual costs of service through a FERC tariff to the Company and the other VYNPC sponsors.

In anticipation of the Vermont Yankee sale to Entergy, the Company sought and the PSB approved two Accounting Orders that allow the Company to defer certain costs incurred in 2002 resulting from the sale. The Company believes that such amounts are probable of future recovery. Based on the approved Accounting Orders, the Company recorded the following in 2002:

- A deferral of approximately $5.3 million related to incremental costs associated with the sale including increased purchased power costs in 2002 under the PPA compared to costs if the Company had continued to own the plant. The PPA is forecasted to result in higher purchased power costs in the initial years of the contract and costs savings in future years when compared to continued ownership of the plant.
- A deferral of $2.9 million related to incremental income tax expense resulting from the sale of Vermont Yankee.

In 2002, the Company also recorded the following after-tax items resulting from the sale, 1) a one-time expense of $0.6 million related to a shareholder payment to the non-Vermont owners of the plant in order to complete the sale, and 2) a $2.5 million favorable impact primarily due to state tax benefits available to Vermont Yankee as a result of the sale.

Although the sale closed on July 31, 2002, final accounting for the sale is pending certain regulatory approvals and resolution of certain closing items between the seller and purchaser. Cash distributions related to the sale will be received in 2003 or 2004.

Nuclear Generating Companies The Company is one of several sponsor companies who have ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic (the "Yankee companies"). The Company is responsible for paying its entitlement shares, which are equal to its ownership percentages, of decommissioning costs for all three plants.

The Yankee companies have been permanently shut down and are currently conducting decommissioning activities. Each plant revises its revenue requirement forecasts on an ongoing basis, including estimates for decommissioning costs, based on site-specific studies, through the projected completion date of all decommissioning activity. Based on revised estimates in 2002, the costs of decommissioning Maine Yankee, Connecticut Yankee and Yankee Atomic increased by $40 million, $150 million and $190 million, respectively, over prior estimates utilized at the FERC. These increased costs are attributable mainly to increases in the projected costs of spent fuel storage, security and liability and property insurance.

The Company's share of estimated future payments related to the decommissioning efforts based on current forecasts, including the incremental cost increases described above, are as follows (dollars in millions):

	Date of Study	Estimated Obligation (a)	Revenue Requirements (b)	Company Share
Maine Yankee	2002	$359.4	$441.9	$9.0
Connecticut Yankee	2002	$414.1	$366.0	$7.3
Yankee Atomic	2002	$321.0	$224.9	$7.9

(a) Represents estimated remaining decommissioning costs, for the period 2002 through 2022 for Yankee Atomic and through 2023 for Maine Yankee and Connecticut Yankee, in 2002 dollars.
(b) Revenue requirements reflect the future payments required by the sponsor companies to recover estimated decommissioning and all other costs in nominal dollars, except for Yankee Atomic, which has collected all other costs except for the increased estimated decommissioning costs described above.

The Company's share of estimated revenue requirements are reflected on the Consolidated Balance Sheets as either regulatory assets or other deferred charges, depending on current recovery in existing rates, and nuclear decommissioning liabilities (current and non-current). At December 31, 2002, the Company had regulatory assets of approximately $9 million and $3.8 million related to Maine Yankee and Connecticut Yankee, respectively, and other deferred charges of $3.5 million and $7.9 million related to Connecticut Yankee and Yankee Atomic, respectively. These amounts are subject to ongoing review and revisions, and the Company adjusts the associated regulatory assets, other deferred charges and nuclear decommissioning liabilities accordingly.

The decision to prematurely retire these nuclear power plants was based on economic analyses of the costs of operating them compared to the costs of closing them and incurring replacement power costs over the remaining period of the plants' operating licenses. The Company believes that the premature retirements would have the effect of lowering costs to customers. The Company believes that based on the current regulatory process, its proportionate share of Maine Yankee's, Connecticut Yankee's and Yankee Atomic's decommissioning costs will be recovered through the regulatory process. Therefore, the ultimate resolution of the premature retirement of the three plants has not and should not have a material adverse effect on the Company's earnings or financial condition.

Maine Yankee In 1997, the Maine Yankee nuclear power plant was prematurely retired from commercial operation. The Company relied on Maine Yankee for less than 5 percent of its required system capacity. Currently, costs billed to the Company by Maine Yankee, including a provision for ultimate decommissioning of the plant, are expected to be paid over the period 2003 through 2008, and are being collected from the Company's customers through existing retail and wholesale rate tariffs.

Maine Yankee's current billings to the sponsor companies are based on its most recent rate case settlement, approved by the FERC on June 1, 1999. The settlement provides for recovery of anticipated future payments for closing, decommissioning and recovery of the remaining investment in Maine Yankee and also resolved all issues raised in the FERC proceeding, including those raised by the secondary purchasers, who purchased Maine Yankee power through agreements with the original owners. Under the rate case settlement, Maine Yankee agreed to file with the FERC a rate proceeding with an effective date for new rates of no later than January 1, 2004. Maine Yankee is expected to seek recovery of the incremental cost increase described above in its next FERC rate filing.

Connecticut Yankee In 1996, the Connecticut Yankee nuclear power plant was prematurely retired from commercial operation. The Company relied on Connecticut Yankee for less than 3 percent of its required system capacity. Currently, costs billed to the Company by Connecticut Yankee, including a provision for ultimate decommissioning of the plant, are expected to be paid over the period 2003 through 2007 and are being collected from the Company's customers through existing retail and wholesale rate tariffs.

Connecticut Yankee's current billings to the sponsor companies are based on its most recent FERC approved rates, which became effective September 1, 2000. Connecticut Yankee is expected to seek recovery of the incremental cost increase described above in its next scheduled FERC rate filing.

Yankee Atomic In 1992, the Yankee Atomic nuclear power plant was retired from commercial operation. The Company relied on Yankee Atomic for less than 1.5 percent of its system capacity. Costs related to Yankee Atomic are not included in the Company's existing rates due to Yankee Atomic's determination in July 2001 that it had collected sufficient funds to complete the decommissioning effort and discontinued related billings to the sponsor companies at that time. Changes to decommissioning cost estimates, however, are subject to ongoing review and such changes would require FERC review and approval.

Yankee Atomic plans to file its rate application with the FERC for recovery of the incremental cost increase described above in March 2003. Billings to sponsors for recovery of these costs are expected to resume in June 2003, for recovery through 2010.

Vermont Electric Power Company, Inc. ("VELCO") Summarized unaudited financial information for VELCO is as follows (dollars in thousands):

	December 31		
Earnings	2002	2001	2000
Transmission revenues	**$20,257**	$19,785	$17,711
Operating income	**$5,091**	$3,214	$2,684
Net income	**$1,094**	$1,118	$1,257
Company's equity in net income	**$516**	$585	$645

	December 31	
Investment	2002	2001
Current assets	**$23,118**	$22,758
Non-current assets	**83,635**	66,574
Total assets	**106,753**	89,332
Less:		
Current liabilities	**38,566**	22,597
Non-current liabilities	**58,991**	58,748
Net assets	**$9,196**	$7,987
Company's equity in net assets	**$4,581**	$4,371

VELCO and its wholly owned subsidiary, Vermont Electric Transmission Company, Inc., own and operate transmission systems in Vermont over which bulk power is delivered to all electric utilities in the state. VELCO has entered into transmission agreements with the State of Vermont and the electric utilities and under these agreements bills all costs, including interest on debt and a fixed return on equity, to the state and others using the system. These contracts enable VELCO to finance its facilities primarily through the sale of first mortgage bonds.

VELCO operates pursuant to the terms of the 1985 Four-Party Agreement (as amended) with the Company and two other major distribution companies in Vermont. Although the Company owns 50.6 percent of VELCO's outstanding common stock, the Four-Party Agreement does not provide the Company the ability to exercise control over VELCO. Therefore, VELCO's financial statements have not been consolidated. Included in VELCO's revenues shown above are transmission services to the Company (reflected as production and transmission expenses in the accompanying Consolidated Statements of Income) amounting to $11.7 million, $10.5 million and $9.8 million for 2002, 2001 and 2000, respectively.

On July 15, 2002, the FERC approved the Company's and GMP's joint request for authorization for each to purchase certain shares of non-voting, $100 par value, Class C common stock issued by VELCO. Under the transaction VELCO can issue up to 16,170 shares of Class C common stock to provide working capital, maintain a debt-to-equity ratio within the guidelines of VELCO's Articles of Association, and to realign equity ownership as close as possible to entitlement levels of VELCO's transmission services. In the third quarter of 2002, the Company acquired additional shares of VELCO's Class C common stock, in the amount of $0.5 million. As a result of other owners acquiring additional shares of VELCO's Class C common stock, in 2002 the Company's common stock ownership in VELCO changed from 56.8 percent to 50.6 percent.

The Company received $0.2 million in 2002 and in 2001 related to the return of capital from VELCO's Class C preferred stock.

NOTE 3 – NON-UTILITY INVESTMENTS

Catamount Catamount invests through its wholly owned subsidiaries in non-regulated energy generation projects in the United States and Western Europe. As of December 31, 2002, through its wholly owned subsidiaries, Catamount has interests in eight operating independent power projects located in Glenns Ferry and Rupert, Idaho; Rumford, Maine; East Ryegate, Vermont; Thetford, England; Hopewell, Virginia; Thuringen, Germany and Mecklenburg-Vorpommern, Germany. Certain financial information for Catamount's investments is set forth in the table that follows (dollars in thousands):

Projects	Location	Generating Capacity	Fuel	In-Service Date	Ownership	Investment December 31 2002	2001
Rumford Cogeneration	Maine	85 MW	Coal/Wood	1990	15.1%	$18,682	$18,086
Ryegate Associates	Vermont	20 MW	Wood	1992	33.1%	7,190	6,544
Appomattox Cogeneration	Virginia	41 MW	Coal/Biomass/Black liquor	1982	25.3%	4,180	6,560
Rupert Cogeneration Partners	Idaho	10 MW	Gas	1996	50.0%	261	-
Glenns Ferry Cogeneration	Idaho	10 MW	Gas	1996	50.0%	76	-
Fibrothetford Limited	England	38.5 MW	Biomass	1998	44.7%	2,807	2,529
Heartlands Power Limited	England	98 MW	Gas	1999	50.0%	-	6,377
Gauley River Power Partners	West Virginia	80 MW	Water	2001	50.0%	-	8,500
DK Burgerwindpark Eckolstadt	Germany	13 MW	Wind	2000	10.0%	335	356
DK Windpark Kavelstorf GmbH&Co. KG	Germany	7.2 MW	Wind	2001	10.0%	145	143
Other	Various		Wind			50	-
						$33,726	$49,095

Catamount's earnings were $1.5 million for 2002 and its loss and earnings were $8.7 million and $0.7 million for 2001 and 2000, respectively. Catamount has projects under development in the United States and Western Europe. In 2001, Catamount undertook a comprehensive strategic review of its operations and refocused its efforts from being an investor in late-stage renewable energy to being primarily focused on developing, owning and operating wind energy projects. Wind energy is competitive with other forms of electric generation and has low production costs compared to other renewable energy sources. Environmental and energy security concerns support growth in the wind sector. Catamount is currently pursuing the sale of certain of its interests in non-wind electric generating assets. Information regarding certain of Catamount's investments follows.

Heartlands Power Limited On October 30, 2002, Catamount sold its 50 percent interest in Heartlands Power Limited to a third party. The proceeds from the sale approximated the net book value of its investments. Previously, in the third quarter of 2002, Catamount recorded an after-tax impairment charge to earnings of $1.3 million related to the pending sale.

Gauley River Catamount entered into a Purchase and Sale Agreement, dated June 30, 2002, with a third party, for the sale of its Gauley River investment interests. In the third quarter of 2002, Catamount recorded an additional $0.8 million after-tax impairment charge to earnings based on funding certain escrow accounts as a condition of the Purchase and Sale Agreement. The sale was consummated on December 5, 2002 and the proceeds from the sale approximated the net book value of its investments in Gauley River.

Catamount began to actively market for sale its project interests in Gauley River during the fourth quarter of 2001 and as a result, in the fourth quarter of 2001, Catamount recorded an after-tax impairment charge to earnings of $1.4 million. The impairment was based on bids received from third parties, less estimated costs to sell.

Fibrothetford Limited To the extent required, continuing equity losses have been applied as a reduction to Catamount's note receivable balance from Fibrothetford. In 2002, Catamount reserved approximately $1.5 million against interest income on the note receivable.

On December 30, 2002, Catamount entered into a Sale and Purchase Agreement with a third party for the sale of its Fibrothetford investment interests. The buyer can terminate the Agreement if the sale has not been consummated prior to March 31, 2003. The Company expects the sale to occur and expects the proceeds from the sale to approximate the net book value of its investments in Fibrothetford.

Catamount began to market for sale its interests in Fibrothetford in late 2001 and as a result, in the fourth quarter of 2001, Catamount recorded an after-tax impairment charge to earnings of $3.2 million and a valuation allowance for the $2.2 million deferred tax asset. The impairment charge was based on the expected market value of Catamount's interest given the project's current financial condition.

Catamount's equity investment in Fibrothetford was reduced to zero in the second quarter of 2001 as a result of losses incurred.

Glenns Ferry and Rupert In June 2002, the steam host for Rupert sold its manufacturing operations and on June 25, 2002, Rupert entered into a new thermal energy service agreement with a new steam host. As a result of the steam host restructuring, Catamount reassessed its investment in Rupert and reinstated the equity method of accounting for its investment. In July 2002, the steam host for Glenns Ferry sold its manufacturing operations and on July 9, 2002, Glenns Ferry entered into a new thermal energy service agreement with a new steam host. As a result, Catamount reassessed its investment in Glenns Ferry and reinstated the equity method of accounting. Both Rupert and Glenns Ferry were issued an Events of Default notice by their lender in May 2002. The steam host restructurings cured most of the events of default identified in the Events of Default notices. Management anticipates that Rupert will cure its remaining events of default in the first quarter of 2003 and that Glenns Ferry will cure its remaining events of default in the late second or early third quarter of 2003.

In August 2002, Catamount began to actively market for sale its project interests in Rupert and Glenns Ferry. Previously in the fourth quarter 2001, Catamount recorded impairment charges for all of its interests in the Rupert and Glenns Ferry projects for a total after-tax charge of $3 million. This charge reduced the value of these investments to zero. The impairment charges were the result of the deteriorating financial condition of the projects' steam hosts that are essential to the projects' Qualifying Facility status and long-term viability.

Eversant Eversant has a $1.4 million equity investment, representing a 12.1 percent ownership interest in The Home Service Store, Inc. ("HSS"), as of December 31, 2002. HSS has established a network of affiliate contractors who perform home maintenance repair and improvements for HSS members. HSS began operations in 1999 and is subject to risks and challenges similar to a company in the early stage of development. In September 2001, Eversant recorded a $1.2 million after-tax write-down of its investment in HSS to fair value. Eversant had previously recorded losses of $9 million related to its investment in HSS. Eversant accounts for its investment in HSS on a cost basis.

During 2001, AgEnergy (formerly SmartEnergy Control Systems), a wholly owned subsidiary of Eversant, filed a claim in arbitration against Westfalia-Surge, the exclusive distributor that marketed and sold its SmartDrive Control product. The arbitration concerned the Company's claim that Westfalia-Surge had not conducted itself in accordance with the exclusive distributorship agreement between the parties. On January 28, 2002, the Company received an adverse decision related to the arbitration proceeding with Westfalia-Surge. On November 6, 2002, Westfalia filed a Petition to Confirm the Arbitrator's Award in the United States District Court for the Western District of Wisconsin, which effectively sought to expand the Arbitrator's Award. The Company submitted an answer seeking to dismiss the Petition to the extent it sought costs in excess of those established by the Arbitrator. The Company cannot predict the outcome of the proceeding.

SmartEnergy Water Heating Services, Inc. ("SEWHS"), a wholly owned subsidiary of Eversant, had earnings of $0.3 million, $0.4 million and $0.5 million for 2002, 2001 and 2000, respectively.

In the first quarter of 2002, the Company decided to discontinue Eversant's efforts to pursue non-regulated business opportunities but will continue its water heating business through SEWHS. Overall, Eversant incurred net losses of $0.5 million, $2.1 million and $2.3 million for 2002, 2001 and 2000, respectively.

NOTE 4 - COMMON STOCK

From 1994 through 1997, the Company purchased 363,447 shares of its common stock in open market transactions, at an average price of $13.04 per share, through a common stock repurchase program that was suspended in 1997. These transactions, net of 245,036 shares sold in connection with the Company's stock option plans and 53,557 sold in connection with the Company's Dividend Reinvestment and Common Stock Purchase Plan, are recorded as treasury stock, at average cost, in the Company's Consolidated Balance Sheets.

NOTE 5 - REDEEMABLE PREFERRED STOCK

The 8.3 percent Dividend Series Preferred Stock is redeemable at par through a mandatory sinking fund in the amount of $1 million per annum and, at its option, the Company may redeem at par an additional non-cumulative $1 million per annum. The Company paid the mandatory sinking fund payment in the amount of $1 million in the first quarter of 2002. In the third quarter of 2002, the Company repurchased $3 million of its 8.3 percent Dividend Series Preferred Stock from one of the Company's preferred shareholders. In the fourth quarter of 2002, the Company paid the mandatory first quarter 2003 payment in the amount of $1 million and an optional 2002 sinking fund payment in the amount of $1 million. See Note 9 – Financial Instruments for fair value of redeemable preferred stock.

NOTE 6 - STOCK AWARD PLANS

Stock Option Plans The Company has awarded stock options to key employees and non-employee directors under various option plans approved in 1988, 1993, 1997, 1998 and 2000. The 2002 plan was approved in May 2002, however, no options were granted from that plan in 2002. Subject to adjustment for stock-splits and similar events, the aggregate number of common shares that may be awarded under these plans is 1,646,875 shares of the Company's common stock including shares issued in lieu of or upon reinvestment of dividends arising from awards. Options are granted at the full market price of the common shares on the date of grant and the maximum term of an option may not exceed five and ten years for non-employee directors and key employees, respectively. Additional information regarding the various option plans is provided in the following tables:

Plan	Authorized	Outstanding at December 31,2002	Available for Future Grant
1988	334,375	55,025	-
1993	150,000	-	-
1997	350,000	209,160	49,640
1998	112,500	90,900	-
2000	350,000	216,200	91,300
2002	350,000	-	350,000
Total	**1,646,875**	**571,285**	**490,940**

Option activity during the past three years was as follows:

	2002	2001	2000
Options outstanding at January 1	**494,585**	518,485	479,860
Exercised	**(28,700)**	(98,550)	(23,700)
Granted	**109,900**	121,150	100,550
Expired/canceled	**(4,500)**	(46,500)	(38,225)
Options outstanding at December 31	**571,285**	494,585	518,485

Summarized information regarding stock options outstanding and exercisable at December 31, 2002:

		Weighted Average	
Range of Exercise Prices	Number Options	Remaining Contractual Life (Years)	Exercise Price
\$10.5625 - \$13.5625	219,760	5.3	\$10.9617
\$13.5626 - \$16.2250	222,125	5.7	\$15.2493
\$16.2260 - \$18.4375	10,500	1.3	\$18.4375
\$18.4376 - \$19.0750	82,000	9.3	\$19.0750
\$19.0760 - \$24.3125	36,900	3.4	\$20.4318
	571,285	5.8	\$14.5424

The stock options granted during 2002, 2001 and 2000 have a weighted-average grant date fair value of \$3.5659, \$2.8467 and \$2.4265, respectively. The fair value was estimated using the binomial model with the following weighted-average assumptions:

	2002	2001	2000
Volatility	**.2548**	.3328	.2872
Risk-free rate of return	**5.50%**	5.75%	6.50%
Dividend yield	**6.61%**	7.42%	7.32%
Expected life (years)	**7.14**	6.09	4.15

Restricted Stock Plans The Company has restricted stock plans in which common stock is granted to certain executive officers, key employees and non-employee directors. Recipients are not required to provide consideration to the Company under these plans, other than rendering service, and have the right to vote the shares and to receive dividends under the plans. The Company accounts for these stock plans under APB 25.

Under the Company's 1997 Restricted Stock Plan ("Restricted Plan"), the total market value of the shares, at grant date, is treated as deferred compensation and charged to expense over the applicable vesting period. Interim estimates of compensation expense are recorded at the end of each reporting period based on a combination of the then-fair market value of the stock and the extent or degree of compliance with the performance criteria. Restricted Plan stock expense was \$134,229 in 2002, \$97,161 in 2001 and \$74,395 in 2000.

As part of the Company's Long-Term Incentive Plan, restricted performance shares of common stock have been awarded to executive officers under the 1999, 2000, 2001 and 2002 Performance Share Plans ("Performance Share Plan"). These awards vary from zero to two- times the number of conditionally granted shares based on the Company achieving certain financial goals over three-year performance cycles. The total market value of the shares is treated as deferred compensation and charged to expense on a quarterly basis over the respective performance cycles based on changes in market value, achievement of financial goals and changes in employment. Performance Share Plan stock compensation charged to expense was \$1,009,896 in 2002, \$1,014,851 in 2001 and \$200,712 in 2000.

Summarized information regarding the awards for both parts of the Restricted Plan is as follows:

	2002	2001	2000
Shares issued	**28,054**	5,813	17,475
Average market value per share	**\$16.70**	\$15.63	\$10.64
Shares forfeited	**-**	1,660	-
Average market value per share	**-**	\$10.99	-

NOTE 7 - LONG-TERM DEBT AND SINKING FUND REQUIREMENTS

The Company's long-term debt consisted of the following (dollars in thousands):

	2002	2001
First Mortgage Bonds:		
9.26%, Series GG, due 2002	**-**	\$3,000
9.97%, Series HH, due 2003	**\$3,000**	7,000
6.01%, Series MM, due 2003	**7,500**	7,500
6.27%, Series NN, due 2008	**3,000**	3,000
6.90%, Series OO, due 2023	**17,500**	17,500
8.91%, Series JJ, due 2031	**15,000**	15,000
Second Mortgage Bonds:		
8.125%, due 2004	**75,000**	75,000
New Hampshire Industrial Development Authority Bonds		
5.5%, due 2009	**5,450**	5,500
Vermont Industrial Development Authority Bonds		
Variable, due 2013 (1.35% at December 31, 2002)	**5,800**	5,800
Connecticut Development Authority Bonds		
Variable, due 2015 (1.30% at December 31, 2002)	**5,000**	5,000
Other, various	**21,537**	22,696
	158,787	166,996
Less current portion	**20,879**	7,225
Total long-term debt	**\$137,908**	\$159,771

Utility Based on outstanding debt at December 31, 2002, the aggregate amount of utility long-term debt maturities and sinking fund requirements are \$10.5 million and \$75 million for the years 2003 and 2004, respectively. No payments are due for 2005 through 2007. It is currently anticipated that all, or a majority of, the \$75 million Second Mortgage Bonds, maturing on August 1, 2004, will be refinanced at maturity. Substantially all of the Company's Vermont utility property and plant is subject to liens under the First and Second Mortgage Bonds.

The Company has an aggregate of \$16.9 million of letters of credit with Citizen's Bank of Massachusetts, expiring on August 31, 2003. These letters of credit support three series of Industrial Development/Pollution Control Bonds, totaling \$16.3 million. The letter of credit supporting the \$5.5 million Seabrook bonds was effective on August 22, 2002. The Company had in place a supplemental indenture allowing the letter of credit to transfer. These letters of credit are secured by a first mortgage lien on the same collateral supporting the Company's first mortgage bonds.

The Company's long-term debt arrangements contain financial and non-financial covenants. At December 31, 2002, the Company was in compliance with all debt covenants related to its various debt agreements.

Non-Utility Catamount has a $25 million revolving credit/term loan facility and letters of credit, of which $21.3 million was outstanding at December 31, 2002. The facility expired on November 12, 2002 and on December 31, 2002 Catamount and its lender entered into the First Amendment to the facility that, among other things, extended the revolver facility for an additional two years. Under the two-year extension, Catamount can borrow against new operating projects subject to the terms and conditions of the facility. Additionally, the outstanding revolver loans were converted to amortizing loans on a two-year term-out schedule. The interest rate is variable, prime-based. Catamount's assets secure the facility. Based on total outstanding debt of $21.5 million at December 31, 2002, including Catamount's office building mortgage, the aggregate amount of Catamount's long-term debt maturities are $10.4 million and $11.1 million for the years 2003 and 2004, respectively. Catamount's long-term debt contains financial and non-financial covenants. Catamount received a waiver by the lender on October 31, 2002 for capital expenditures that exceeded the annual budget. At December 31, 2002, Catamount was in compliance with all covenants under the revolver. In early January 2003, Catamount applied $12.6 million, representing the after-tax proceeds from its investment sales, against its outstanding loan balance resulting in a $8.7 million loan balance.

In 2002, SmartEnergy Water Heating Services, Inc. retired a $1.1 million term loan with Bank of New Hampshire.

See Note 9 – Financial Instruments for additional information related to fair value of long-term debt.

NOTE 8 – RECONCILIATION OF NET INCOME AND AVERAGE SHARES OF COMMON STOCK AND OTHER COMPREHENSIVE INCOME

The following table represents a reconciliation of net income to net income available for common stock and the average common shares outstanding basic to diluted (dollars in thousands):

	Years Ended December 31		
	2002	2001	2000
Net income	**$19,767**	$2,407	$18,043
Preferred stock dividend requirements	**1,528**	1,696	1,779
Net income available for common stock	**$18,239**	$711	$16,264
Average shares of common stock outstanding – basic	**11,678,239**	11,551,042	11,488,351
Dilutive effect of stock options	**110,614**	94,470	6,777
Dilutive effective of performance plan shares	**153,969**	134,723	36,762
Average shares of common stock outstanding – diluted	**11,942,822**	11,780,235	11,531,890

Components of other comprehensive income, as shown in the Consolidated Financial Statements are as follows (dollars in thousands):

	Years Ended December 31		
	2002	2001	2000
Net Income	**$19,767**	$2,407	$18,043
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	**800**	(349)	-
Non-qualified benefit obligation	**(27)**	(5)	(23)
	773	(354)	(23)
Comprehensive income	**$20,540**	$2,053	$18,020

NOTE 9 – FINANCIAL INSTRUMENTS

The estimated fair values of the Company's financial instruments at December 31, 2002 and 2001 are as follows (dollars in thousands):

	2002		2001	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	**$8,054**	**$4,931**	$8,054	$3,815
Preferred stock subject to mandatory redemption	**$10,000**	**$10,339**	$16,000	$16,000
Long-term debt:				
First mortgage bonds	**$46,000**	**$49,828**	$53,000	$52,259
Second mortgage bonds	**$75,000**	**$80,243**	$75,000	$76,163
Other long-term debt	**$37,787**	**$37,798**	$38,996	$38,996

The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value because of the short maturity of those instruments. The Company has a derivative related to a component of the Hydro-Quebec contract, which is explained in more detail in Note 13 – Commitments and Contingencies. The estimated fair value of this derivative is based on quoted market information where available and appropriate modeling methodologies.

Preferred stock and long-term debt: The fair value of the Company's fixed rate securities is estimated based on quoted market prices for the same or similar issues or on current rates offered to the Company for the same remaining maturation. Adjustable rate securities are assumed to have a fair value equal to their carrying value.

Supplemental Executive Retirement Plan ("SERP") Investments: Investments held for the benefit of the SERP are recorded at fair value at December 31, 2002 and 2001, in the amount of $4.2 million and $5.1 million, respectively and are included in Other Current Assets in the Company's Consolidated Balance Sheets.

NOTE 10 – PENSION AND POSTRETIREMENT BENEFITS

The Company has a non-contributory trusteed pension plan covering all employees (union and non-union). Under the terms of the pension plan, employees are vested after completing five years of service, and can retire when they are at least age 55 with a minimum of 10 years of service, and are eligible to receive monthly benefits or a lump sum amount. The Company's funding policy is to contribute at least a statutory minimum to a trust. The Company is not required by its union contract to contribute to multi-employer plans.

On January 1, 2002, the Company's pension plan was amended to include enhanced early retirement reduction factors and death benefits for beneficiaries of deceased active participants. The Company updated the assumed rates of retirement to reflect expected experience. The Company also adopted the GAR 94 mortality table and a heavier withdrawal assumption, as well as the GAR 94 lump sum basis required by IRS Revenue Ruling 2001-62.

The Company also sponsors a defined benefit postretirement medical plan that covers all employees who retire with 10 years or more of service and at least age 55. The Company funds this obligation through a Voluntary Employees' Benefit Association and 401(h) Subaccount in its pension plan.

The following table sets forth information on the plans' benefit obligations, fair value of the plans' assets, the respective plans' funded status and amounts recognized in the Company's Consolidated Balance Sheets and Consolidated Statements of Income (dollars in thousands):

	At December 31			
	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
Change in Benefit Obligation				
Benefit obligation at beginning of year (January 1)	**$71,241**	$64,382	**$16,082**	$14,800
Service cost	**2,337**	2,138	**331**	243
Interest cost	**5,354**	5,046	**1,153**	1,114
Amendments	**3,075**	-	**-**	-
Actuarial loss	**6,415**	3,699	**4,758**	2,874
Benefits paid	**(4,924)**	(4,024)	**(1,812)**	(2,949)
Projected obligation as of measurement date (September 30)	**$83,498**	$71,241	**$20,512**	$16,082
Change in plan assets				
Fair value of plan assets at beginning of year (January 1)	**$65,629**	$80,202	**$909**	$1,075
Actual return on plan assets	**(6,414)**	(10,549)	**10**	31
Employer contribution	**-**	-	**4,919**	2,752
Benefits paid	**(4,924)**	(4,024)	**(1,812)**	(2,949)
Fair value of assets as of measurement date (September 30)	**$54,291**	$65,629	**$4,026**	$909
Reconciliation of funded status				
Benefit obligation	**$(83,498)**	$(71,241)	**$(20,512)**	$(16,082)
Fair value of assets	**54,291**	65,629	**4,026**	909
Company contributions between measurement and year-end dates	**-**	-	**652**	3,584
Funded Status	**(29,207)**	(5,612)	**(15,834)**	(11,589)
Unrecognized net transition (asset) obligation	**(291)**	(437)	**2,558**	2,814
Unrecognized prior service cost	**4,483**	1,703	**-**	-
Unrecognized net actuarial loss (gain)	**14,973**	(4,942)	**10,629**	6,003
Accrued benefit cost	**(10,042)**	(9,288)	**(2,647)**	(2,772)
FAS 71 regulatory asset (1997 VERP)	**-**	25	**-**	25
Accrued benefit cost	**$(10,042)**	$(9,263)	**$(2,647)**	$(2,747)

	Pension Benefits			Postretirement Benefits		
	2002	2001	2000	2002	2001	2000
Net benefit costs include the following components						
Service cost	**$2,337**	$2,138	$1,901	**$331**	$243	$183
Interest cost	**5,354**	5,046	4,614	**1,153**	1,114	984
Expected return on plan assets	**(6,493)**	(6,244)	(5,873)	**(243)**	(102)	(100)
Amortization of prior service cost	**295**	191	191	**-**	-	-
Recognized net actuarial loss (gain)	**(594)**	(776)	(550)	**416**	135	51
Amortization of transition (asset) obligation	**(146)**	(146)	(146)	**256**	256	256
Supplemental adjustment for amortization of FAS 71 Regulatory asset (1997 VERP)	**25**	466	466	**25**	457	457
Accelerated amortization of FAS 71 Regulatory asset (1997 VERP)	**-**	441	-	**-**	431	-
Net periodic benefit cost	**778**	1,116	603	**1,938**	2,534	1,831
Less amount allocated to other accounts	**100**	28	21	**253**	219	214
Net benefit costs expensed	**$678**	$1,088	$582	**$1,685**	$2,315	$1,617

Weighted average assumptions as of measurement date (September 30):	Pension Benefits			Postretirement Benefits		
	2002	2001	2000	2002	2001	2000
Weighted average discount rates	**6.50%**	7.25%	7.75%	**6.50%**	7.25%	7.75%
Expected long-term return on assets	**8.50%**	8.50%	9.25%	**8.50%**	8.50%	8.50%
Rate of increase in future compensation levels	**4.00%**	4.50%	4.50%	**4.00%**	4.50%	4.50%
Per capita percent increase in health care costs:						
Pre-65	**n/a**	n/a	n/a	**10.00%**	11.00%	6.00%
Post-65	**n/a**	n/a	n/a	**9.50%**	10.50%	5.50%

The expected long-term return on assets rate of 8.5 percent was used to determine expense for 2002. The rate that will be used to determine 2003 expense is 8.25 percent.

For measurement purposes, a 10 percent and 9.5 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2003, for pre-65 and post-65 claims costs, respectively.

Increasing (decreasing) the assumed health care cost trend rates by one percentage point in each year would have resulted in an increase (decrease) of $1,157,467 and $(1,002,334), respectively, in the accumulated postretirement benefit obligation as of December 31, 2002 and an increase (decrease) of approximately $76,744 and $(66,355), respectively, in the aggregate service cost and interest cost components of net periodic postretirement benefit cost for 2002.

The Company provides postemployment benefits consisting of long-term disability benefits. The accumulated postemployment benefit obligation at December 31, 2002 and 2001 of $1.2 million and $1.1 million, respectively, is reflected in the Company's Consolidated Balance Sheets as a liability. The pre-tax postemployment benefit costs charged to expense in 2002, 2001 and 2000, including insurance premiums, were $225,000, $271,000, and $481,000 respectively.

The Company maintains a 401(k) Savings Plan for substantially all employees. This savings plan provides for employee pre-tax and post-tax contributions up to specified limits. The Company matches employee pre-tax contributions up to a maximum of 4 percent of eligible compensation. Eligible employees are at all times 100 percent vested in their pre-tax and post-tax contribution account and in their matching employer contribution. The matching contributions made by the Company were $1.1 million for 2002 and $1 million for each year 2001 and 2000.

NOTE 11 – INCOME TAXES

The components of federal and state income tax expense are as follows (dollars in thousands):

	Years Ended December 31		
	2002	2001	2000
Federal:			
Current	**$9,208**	$10,625	$12,195
Deferred	**679**	(3,713)	(2,542)
Investment tax credits, net	**(391)**	(391)	(391)
	9,496	6,521	9,262
State:			
Current	**2,773**	2,976	3,440
Deferred	**55**	(1,113)	(891)
	2,828	1,863	2,549
Total federal and state income taxes	**$12,324**	$8,384	$11,811
Federal and state income taxes charged to:			
Operating expenses	**$12,234**	$11,472	$9,034
Other income	**90**	(2,964)	2,777
Extraordinary loss	**-**	(124)	-
	$12,324	$8,384	$11,811

The principal items comprising the difference between the total income tax expense and the amount calculated by applying the statutory federal income tax rate to income before tax are as follows (dollars in thousands):

	Years Ended December 31		
	2002	2001	2000
Income before income tax	**$32,633**	$10,791	$29,854
Federal statutory rate	**35%**	35%	35%
Federal statutory tax expense	**11,422**	3,777	10,449
Increases (reductions) in taxes resulting from:			
Dividend received deduction	**(1,067)**	(741)	(895)
Deferred taxes on plant	**(20)**	147	453
State income taxes net of federal tax benefit	**1,822**	1,203	1,735
Investment credit amortization	**(391)**	(391)	(391)
AFUDC equity	**216**	214	209
Valuation allowance	**257**	3,985	-
Other	**85**	190	251
Total income tax expense provided	**$12,324**	$8,384	$11,811

Tax effects of temporary differences and tax carryforwards that give rise to significant portions of the deferred tax assets and deferred tax liabilities are presented below (dollars in thousands):

	At December 31		
	2002	2001	2000
Deferred tax assets			
Purchased power accrual	**-**	-	$1,213
Equity Losses	**$6,327**	$6,513	-
Accruals and other reserves not currently deductible	**5,422**	2,150	5,164
Retiree medical benefits	**1,062**	1,465	2,669
Deferred compensation and pension	**7,045**	5,679	5,587
Environmental costs accrual	**3,081**	3,811	3,928
Valuation allowance	**(4,241)**	(3,985)	-
Total deferred tax assets	**18,696**	15,633	18,561
Deferred tax liabilities			
Property, plant and equipment	**49,240**	47,518	50,359
Net regulatory asset	**2,518**	2,777	2,913
Conservation and load management expenditures	**102**	1,890	4,222
Vermont Yankee fuel rod maintenance	**1,593**	-	-
Vermont Yankee sale	**5,083**	-	-
Nuclear refueling costs	**315**	1,076	797
Other	**1,611**	1,200	4,049
Total deferred tax liabilities	**60,462**	54,461	62,340
Net deferred tax liability	**$41,766**	$38,828	$43,779

A valuation allowance has been recorded in the amount of $4.2 million to reflect Management's best estimate of deferred income taxes for equity losses that will not ultimately be realized. The valuation allowance increased by $0.3 million from December 31, 2001 to December 31, 2002. All other deferred income taxes are expected to be realized.

NOTE 12 – RETAIL RATES

The Company recognizes that adequate and timely rate relief is necessary if it is to maintain its financial strength, particularly since Vermont regulatory rules do not allow for changes in purchased power and fuel costs to be automatically passed on to consumers through rate adjustment clauses. The Company intends to continue its practice of periodically reviewing costs and requesting rate increases when warranted. The Company currently plans, absent any unforeseen developments, to refrain from changing rates for its Vermont utility customers until at least 2006.

Vermont Retail Rates *2000 Retail Rate Case* In an effort to mitigate eroding earnings and cash flow prospects in the future, due mainly to under-recovery of power costs, on November 9, 2000, the Company filed with the PSB a request for a 7.6 percent rate increase, or $19 million per annum, effective July 24, 2001. The PSB suspended the rate filing and a schedule was set to review the case.

On June 26, 2001, the PSB issued an order approving the Company's May 7, 2001 rate case settlement with the DPS. The rate order ended uncertainty over the future recovery of Hydro-Quebec contract costs, allowed a 3.95 percent rate increase, made the January 1, 1999 temporary rates permanent, permitted a return on equity of 11.0 percent for the 12 months ending June 30, 2002, for the Vermont utility, and created new service quality standards. The Company also agreed to a $9 million one-time write-off ($5.3 million after-tax) of regulatory assets, which was recorded in June 2001, and a rate freeze through January 1, 2003.

In addition to the provisions outlined above, the rate order requires the Company to return up to $16 million to ratepayers in the event of a merger, acquisition or asset sale if such sale requires PSB approval. The 3.95 percent rate increase became effective with bills rendered July 1, 2001. The Company was able to accept the 3.95 percent rate increase versus the 7.6 percent increase it requested since 1) regulatory asset amortizations would decrease approximately $3.5 million, on a 12-month basis, due to the $9 million one-time write-off of regulatory assets and 2) Vermont

Yankee decommissioning costs decreased approximately $1.9 million, on a 12-month basis, after the rate case was filed as a result of an agreement in principle between Vermont Yankee and the secondary purchasers.

As part of the Company's June 26, 2001 rate order, the Company agreed that all amounts collected from the Hydro-Quebec Ice Storm settlement would be applied first to reduce the remaining balance of deferred costs related to the arbitration, with the remaining balance, if any, applied to reduce other regulatory asset accounts as specified by the DPS and approved by the PSB. In July 2001 Hydro-Quebec and the VJO agreed to a final settlement, of which the Company's share was approximately $4.3 million. In the third quarter of 2001, the Company applied approximately $2.7 million to the remaining balance of deferred ice storm arbitration costs. On October 30, 2001, the Company filed a letter with the PSB summarizing its agreement with the DPS on application of the remaining $1.6 million to other regulatory assets. On September 10, 2002 and in response to a PSB request, the Company filed its amended proposal as agreed to with the DPS.

On October 4, 2002, the PSB issued an Order approving the Company's proposal for reducing certain regulatory assets by approximately $2 million through application of the remaining Hydro-Quebec settlement and the ongoing Millstone Unit #3 decommissioning non-payments. Although the Company is recovering the Millstone Unit #3 decommissioning costs in rates, its payments for decommissioning have ceased. In the third quarter of 2002, based on the PSB Order, the Company reduced certain of its regulatory assets related to Conservation and Load Management by approximately $2 million. The Company will account for the ongoing Millstone Unit #3 decommissioning non-payments as a regulatory liability, with carrying charges, to be addressed in the Company's next rate proceeding.

In 2002, the Vermont utility earned approximately $0.4 million, on an after-tax basis, above its allowed rate of return of 11.0 percent. In accordance with its rate case settlement, the Company reduced the Vermont utility's earnings by that amount to satisfy its earnings cap requirement. The related deferral of approximately $0.7 million pre-tax is included in Other deferred credits on the Company's Consolidated Balance Sheet. The Company and DPS are currently in discussions as to the balance sheet classification so as to preserve ratepayer benefit as required by the rate case settlement.

What follows is a discussion of the Company's prior rate case filings; outstanding issues related to these rate filings were resolved as part of the June 2001 rate case settlement.

1997 Retail Rate Case The Company filed for a 6.6 percent general rate increase on September 22, 1997. Approximately 92.9 percent of the rate increase request was to recover scheduled contractual increases in the cost of power the Company purchases from Hydro-Quebec. In response to the rate increase filing, the PSB decided to appoint an independent investigator to examine the Company's decision to buy power from Hydro-Quebec. The Company filed with the PSB stating that the PSB, as well as other parties, should be barred from reviewing past decisions because the PSB already examined the Company's decision to buy power from Hydro-Quebec in a 1994 rate case in which the Company was penalized for "improvident power supply management." The Company sought, and the PSB granted, permission to stay this rate case and to file an interlocutory appeal of the PSB's denial of the Company's motion to preclude a re-examination of the Company's Hydro-Quebec contract in 1991. The Company argued its position before the Vermont Supreme Court. On February 9, 2001, the Vermont Supreme Court issued a decision on the Company's rate case appeal that reversed the PSB's decision on the preclusion issues and remanded the case to the PSB for further proceedings, which were ultimately resolved as part of the June 2001 rate case settlement.

1998 Retail Rate Case On June 12, 1998, the Company filed with the PSB for a 10.7 percent retail rate increase that supplanted the September 22, 1997 rate increase request. On October 27, 1998, the Company reached an agreement with the DPS that provided for a temporary rate increase of 4.7 percent beginning with service rendered on or after January 1, 1999. The agreement was approved by the PSB on December 11, 1998.

The 4.7 percent rate increase was subject to retroactive or prospective adjustment upon future resolution of issues arising under the Hydro-Quebec and Vermont Joint Owner's ("VJO") Power Contract and resulted in pre-tax losses of $7.4 million, $2.9 million, and $11.5 million in 1998, 1999 and 2000, respectively, representing the Company's estimated under-recovery of power costs under the VJO Power Contract. An additional $2.9 million pre-tax loss was recorded in the first quarter of 2001. The Company's June 26, 2001 rate order ended the uncertainty over the future recovery of Hydro-Quebec contract costs, and the Company will no longer incur future losses for under-recovery of Hydro-Quebec contract costs related to any allegations of imprudence prior to the June 26, 2001 rate order. As a result, in the second quarter of 2001, the Company reversed its $2.9 million pre-tax liability related to estimated under-recovery of Hydro-Quebec power costs and discontinued the accrual.

Deseasonalized Rates On July 1, 2000, the Company ended the winter-summer differential and the Company now has flat rates throughout a given year. Winter rates were reduced by 14.9 percent, while summer rates were increased by 10.5 percent. The rate design change was revenue neutral over a 12-month period and the additional revenues in 2000 were applied to reduce regulatory deferrals related to the Hydro-Quebec ice storm arbitration, as directed by the PSB.

New Hampshire Retail Rates Connecticut Valley serves approximately 10,000 customers in the State of New Hampshire. Connecticut Valley's retail rate tariffs, approved by the New Hampshire Public Utilities Commission ("NHPUC"), contain a Fuel Adjustment Clause ("FAC") and a Purchased Power Cost Adjustment ("PPCA"). Under these clauses, Connecticut Valley recovers its estimated annual costs for purchased energy and capacity, which are reconciled when actual data is available.

On December 31, 2001, the NHPUC approved Connecticut Valley's FAC and PPCA rates for 2002 as well as Connecticut Valley's Business Profits Tax Adjustment Percentage and Conservation and Load Management Percentage Adjustment for 2002. Combined with the Temporary Billing Surcharge, the result was an overall 8.6 percent rate reduction with a revenue decrease of $1.8 million.

On June 1, 2000, the New Hampshire electric utilities began delivery of consistent, statewide energy efficiency programs. The NHPUC had previously approved the design of common, core efficiency programs and on February 27, 2002, Connecticut Valley proposed implementation of specific, non-core energy efficiency programs with recovery of costs for all the energy efficiency programs via an Interim 2002 – 2003 Conservation and Load Management Percentage Adjustment effective June 1, 2002. Connecticut Valley had ceased providing such programs in 1997. On May 31, 2002, the NHPUC approved Connecticut Valley's proposal including a 1.4 percent increase in average retail rates to recover the costs. As required by the NHPUC order, the efficiency programs and related rate increase became effective June 1, 2002.

On October 1, 2002, Connecticut Valley implemented New Hampshire's statewide low-income energy assistance program referred to as the Tiered Discount Program ("TDP"). Under this NHPUC approved program, New Hampshire electric utilities collect a system benefits charge, apply discounted rates to participant bills, forgive any past due balances at August 31, 2002, deduct any authorized start-up and administrative costs, and remit the balance to the state. A statewide system benefits charge fund makes up the shortfall if the system benefits charge does not wholly reimburse a particular utility. The NHPUC also approved a $0.0012 per kWh surcharge for Connecticut Valley (which is not subject to the system benefits charge) to fund the TDP.

On December 20, 2002, the NHPUC approved Connecticut Valley's FAC and PPCA rates for 2003 and on December 30, 2002 the NHPUC approved Connecticut Valley's Business Profits Tax Adjustment Percentage for 2003. The 2003 rates are effective January 1, 2003 and result in an overall 8.5 percent rate increase with a revenue increase of $1.6 million.

Connecticut Valley Sale On December 5, 2002, the Company reached agreement for the sale of Connecticut Valley to Public Service Company of New Hampshire ("PSNH"), New Hampshire's largest electric utility. The sale agreement is the result of months of negotiations among Connecticut Valley, the Company, the Governor's Office of Energy and Community Services, staff of the NHPUC, the Office of Consumer Advocate, the City of Claremont and New Hampshire Legal Assistance. Management believes the sale agreement, as structured, should resolve all issues in litigation over

New Hampshire's restructuring plan, Connecticut Valley's rates, recovery of stranded costs and renders moot a pending exit fee decision by the FERC. The proposed closing date for the sale is January 1, 2004.

Under the terms of the sale agreement, PSNH will pay the Company the book value for Connecticut Valley's franchise utility assets, which approximates $9 million at December 31, 2002. PSNH will acquire Connecticut Valley's poles, wires, substations and other facilities, as well as several independent power obligations, including the Wheelabrator contract. Contemporaneously with the sale, PSNH will pay an additional $21 million to the Company as a stranded cost reimbursement for the power resources the Company acquired to serve Connecticut Valley's customers.

The FERC, the NHPUC and possibly the SEC must approve the sale. In addition, as a condition of the sale, the NHPUC must approve the pending settlement in the Wheelabrator docket.

On January 31, 2003, Connecticut Valley, the Company, PSNH and various other parties filed with the NHPUC an "Application for Approval of Settlements and Related Transactions Related to the Implementation of Restructuring in the Area Served by Connecticut Valley Electric Company Inc." ("Application"). The Application seeks approval of a series of agreements related to 1) implementation of restructuring in the geographic area served by Connecticut Valley, 2) resolution of certain litigation between the NHPUC, Connecticut Valley and the Company, and 3) the purchase and sale agreement between the Company, Connecticut Valley and PSNH. The Application proposes a procedural schedule beginning mid-February 2003 with an Order by the end of June 2003.

The sale will result in either a gain or loss; however, the nature and size of such gain or loss will be highly dependent upon power market price forecasts at the time of the sale and mitigation efforts both before and after the sale. Accordingly, the Company cannot estimate at this time such a gain or loss.

If the sale transaction does not close, and if there is an adverse resolution of the pending FERC exit fee proceeding, these events would have a material adverse effect on the Company's results of operations, financial condition and cash flows. However, the Company cannot predict the ultimate outcome of this matter.

FERC Exit Fee Proceedings On February 28, 1997, Connecticut Valley was directed by the NHPUC to terminate its purchase of power from the Company. The Company filed an application with the FERC in June 1997, to recover stranded costs in connection with its wholesale rate schedule with Connecticut Valley and the notice of cancellation of that rate schedule (contingent upon the recovery of the stranded costs that would result from the cancellation of that rate schedule). In December 1997, the FERC rejected the Company's proposal to recover stranded costs through the imposition of a surcharge in the Company's transmission tariff, but indicated that it would consider an exit fee mechanism in the wholesale rate schedule for collecting stranded costs. The FERC denied the Company's motion for a rehearing regarding the transmission surcharge proposal. However, the Company filed a request with the FERC for an exit fee mechanism in the wholesale rate schedule to collect the stranded costs resulting from the cancellation of the wholesale rate schedule. The stranded cost obligation sought to be recovered was $90.6 million in nominal dollars and $44.9 million on a net present value basis as of December 31, 1997.

On April 24, 2001, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision in the Company's stranded cost/exit fee proceeding. The ALJ ruled that if Connecticut Valley terminates its relationship as a wholesale customer of the Company and subsequently becomes a wholesale transmission customer of the Company, Connecticut Valley shall be liable for payment of stranded costs to the Company. The ALJ calculated, on an illustrative pro-forma basis, a nominal stranded cost obligation of nearly $83 million through 2016. The amount of the exit fee as determined by the ALJ will decrease with each year that service continues and normal tariff revenues are collected, and will ultimately be calculated from the date of termination, if notice of termination is ever given.

On October 29, 2002, the Company, jointly with the NHPUC, requested that the FERC defer issuance of its final exit fee order to allow for Connecticut Valley to continue working for a negotiated settlement with parties to the New Hampshire restructuring proceeding and the NHPUC. On December 5, 2002, Connecticut Valley, the State of New Hampshire, the City of Claremont and PSNH reached agreement for the sale of Connecticut Valley to PSNH. Under the terms of the agreement, which is described in more detail above, PSNH will pay an additional $21 million to the Company as a stranded cost reimbursement for the power resources the Company acquired to serve Connecticut Valley's customers, thus rendering moot the exit fee decision by the FERC.

Absent the sale, if the Company was unable to obtain approval by the FERC of an exit fee from its power supply arrangement and Connecticut Valley was forced to terminate its relationship as a wholesale customer of the Company (the earliest termination date that could presently occur pursuant to the wholesale rate schedule is December 31, 2004) it is possible that the Company would be required to recognize a pre-tax loss under the power supply arrangement totaling approximately $27.4 million as of December 31, 2004. The Company would also be required to write-off approximately $0.6 million pre-tax of regulatory assets associated with its wholesale business as of December 31, 2004. The sale of Connecticut Valley to PSNH as currently structured, which includes the receipt of $21 million in stranded cost recovery, is expected to resolve these issues. However, Management cannot predict whether the sale will occur under these terms.

Wheelabrator Power Contract Connecticut Valley purchases power from several Independent Power Producers, who own qualifying facilities as defined by the Public Utility Regulatory Policies Act of 1978. For the 12 months ended December 31, 2002, under long-term contracts with these qualifying facilities, Connecticut Valley purchased 39,258 mWh, of which 93 percent was purchased from Wheelabrator Claremont Company, L.P., ("Wheelabrator") who owns a waste-to-energy electric generating facility. Connecticut Valley had filed a complaint with the FERC stating its concern that Wheelabrator has not been a qualifying facility since the facility began operation. On February 11, 1998, the FERC issued an Order denying Connecticut Valley's request for a refund of past purchased power costs and lower future costs. Connecticut Valley filed a request for rehearing with the FERC on March 13, 1998, which was denied. Connecticut Valley appealed to the D.C. Circuit Court of Appeals, which denied the appeal, but indicated that Connecticut Valley could seek relief from the NHPUC. On May 12, 2000, Connecticut Valley filed a petition with the NHPUC seeking 1) to amend the contract to permit purchase of net, rather than gross, output of the facility and 2) a refund, with interest, of past purchases of the difference between net and gross output.

On March 29, 2002, the NHPUC issued an order denying Connecticut Valley's petition. The NHPUC further found that its original 1983 order did not authorize sales in excess of 3.6 MW and ordered that Connecticut Valley discontinue purchases in excess of that amount at preferential rates. Wheelabrator has been making sales at the long-term rates for up to 4.5 MW of capacity and related energy since it began operations in 1987.

On April 29, 2002, Connecticut Valley, Wheelabrator, NHPUC Staff and the Office of Consumer Advocate submitted a Stipulation of Settlement with the NHPUC that requires Wheelabrator to make five annual payments of $150,000 and a sixth payment of $25,000, and Connecticut Valley to make six annual payments of $10,000, all of which will be credited to customer bills. The Stipulation of Settlement will not become effective unless and until it is approved by the NHPUC. The settlement does not otherwise change the terms of the existing contract between Connecticut Valley and Wheelabrator.

A hearing on the Stipulation of Settlement was held on June 7, 2002 with a focus on determining whether the Stipulation is in the public interest. The NHPUC issued an Order on July 5, 2002, in which it did not rule on the Stipulation of Settlement and instead announced that it would appoint an independent mediator to work with all parties to see if a mutually agreeable settlement of the case could be achieved. The NHPUC selected an independent mediator and, after several mediation sessions, the mediator issued a report on December 18, 2002, which stated that the parties opposing the Stipulation of Settlement before the mediation continued to oppose it after the mediation.

As a condition to the sale of Connecticut Valley to PSNH, the NHPUC must approve the Stipulation of Settlement. Additionally, under the terms of the sale agreement, PSNH will acquire several of Connecticut Valley's independent power obligations, including the Wheelabrator contract.

Connecticut Valley Rate/Federal Court Proceedings In 1998, Management determined that Connecticut Valley no longer qualified for the application of SFAS No. 71, and wrote off all of its regulatory assets associated with its New Hampshire retail business totaling approximately $1.3 million on a pre-tax basis. This determination was based on various legal and regulatory actions including the February 28, 1997 NHPUC Final Plan to restructure the electric utility industry in New Hampshire, a supplemental order that required Connecticut Valley to give notice to cancel its power contract with the Company and denied stranded cost recovery related to this power contract, and a December 3, 1998 Court of Appeals decision stating that Connecticut Valley's rates could be reduced to the level prevailing on December 31, 1997. The Company's petition for rehearing with the Court of Appeals as well as petition for writ of certiorari with the United States Supreme Court were subsequently denied.

As a result of the December 3, 1998 Court of Appeals decision, on March 22, 1999 the NHPUC issued an Order that directed Connecticut Valley to file its calculation of the difference between the total FAC and PPCA revenues that it would have collected had the 1997 FAC and PPCA rate levels been in effect the entire year. The NHPUC also directed Connecticut Valley to calculate a rate reduction to be applied to all billings for the period April 1, 1999 through December 31, 1999 to refund the 1998 over-collection relative to the 1997 rate level. The Company estimated this amount to be approximately $2.7 million on a pre-tax basis. On March 26, 1999, Connecticut Valley filed the required tariff page with the NHPUC, under protest and with reservation of all rights, and implemented the refund effective April 1, 1999.

On April 7, 1999, the Federal District Court ("Court") ruled from the bench that the March 22, 1999 NHPUC Order requiring Connecticut Valley to provide a refund to its retail customers was illegal and beyond the NHPUC's authority and that the NHPUC could not reduce Connecticut Valley's rates below rates in effect at December 31, 1997. Accordingly, Connecticut Valley removed the rate refund from retail rates effective April 16, 1999.

On May 17, 1999, the NHPUC issued an order requiring Connecticut Valley to set temporary rates at the level in effect as of December 31, 1997, subject to future reconciliation, effective with bills issued on and after June 1, 1999. On May 24, 1999, the NHPUC filed a petition for mandamus in the Court of Appeals challenging the Court's May 11, 1999 ruling and seeking a decision allowing the refunds as required by the NHPUC's March 22, 1999 Order. The Court of Appeals denied that petition on June 2, 1999. The NHPUC immediately filed a notice of appeal in the Court of Appeals, again challenging the Court's May 11, 1999 ruling. In that appeal, the Company and Connecticut Valley contended, among other things, that it is unfair for the NHPUC to direct Connecticut Valley to continue to purchase wholesale power from the Company in order to avoid the triggering of a FERC exit fee, but at the same time to freeze Connecticut Valley's rates at their December 31, 1997 level, which does not enable Connecticut Valley to recover all of these power costs.

On June 14, 1999, PSNH and various parties in New Hampshire announced that a "Memorandum of Understanding" had been reached, which was intended to result in a detailed settlement proposal to the NHPUC that would resolve PSNH's claims against the NHPUC's restructuring plan. On July 6, 1999, PSNH petitioned the Court to stay its proceedings related to electric utility restructuring in New Hampshire indefinitely while the proposed settlement was reviewed and approved by the NHPUC and the New Hampshire Legislature. On July 12, 1999, the Company and Connecticut Valley objected to any stay that would allow the NHPUC's rate freeze order to remain in effect for an extended period and asked the Court to proceed with prompt hearings on its summary judgment motion and trial on the merits. On October 20, 1999, the Court heard oral arguments pertaining to the pretrial motions of the Company and the NHPUC for summary judgment and dismissal, respectively.

On December 1, 1999, Connecticut Valley filed with the NHPUC a petition for a change in its FAC and PPCA rates effective on bills rendered on and after January 1, 2000. On December 30, 1999, the NHPUC denied Connecticut Valley's request to increase its FAC and PPCA rates above those in effect at December 31, 1997, subject to further investigation and reconciliation until otherwise ordered by the NHPUC. Accordingly, during the fourth quarter of 1999, Connecticut Valley recorded a pre-tax loss of $1.2 million for under-collection of year 2000 power costs.

The Court of Appeals issued a decision on January 24, 2000, which upheld the Court's preliminary injunction enjoining the Commission's restructuring plan. The decision also remanded the refund issue to the Court stating: "the district court may defer vacation of this injunction against the refund order for up to 90 days. If within that period it has decided the merits of the request for a permanent injunction in a way inconsistent with refunds, or has taken any other action that provides a showing that the Company is likely to prevail on the merits in federal court in barring the refunds, it may enter a superseding injunction against the refund order, which the Commission may then appeal to us. Otherwise, no later than the end of the 90-day period, the district court must vacate its present injunction insofar as it enjoins the Commission's refund order."

On March 6, 2000, the Court granted summary judgment to Connecticut Valley and the Company on their claim under the filed-rate doctrine and issued a permanent injunction mandating that the NHPUC allow Connecticut Valley to pass through to its retail customers its wholesale costs incurred under the rate schedule with the Company. The Court also ruled that Connecticut Valley was entitled to recover the wholesale costs that the NHPUC disallowed in retail rates since January 1, 1997.

Pursuant to the March 6, 2000 Court Order, on March 17, 2000, Connecticut Valley filed a rate request with the NHPUC for an Interim FAC/PPCA to recover the balance of wholesale costs not recovered since January 1997. To mitigate the rate increase percentage, the Interim FAC/PPCA was designed to recover current power costs and a substantial portion of past under-collections by the end of 2000; the remainder of the past under-collections were being collected during 2001 along with 2001 power costs. The NHPUC held a hearing on April 7, 2000 to review the 12.3 percent increase that would raise $1.6 million of revenues in 2000. The NHPUC issued an order approving the rates as temporary effective May 1, 2000.

On July 25, 2000, the Court of Appeals affirmed the Court's March 6, 2000 Order granting summary judgment to Connecticut Valley and the Company. The NHPUC then asked the Court of Appeals to reconsider its decision. That request was denied. As a result of the favorable Court of Appeals action, Connecticut Valley recorded a $2 million after-tax gain in the third quarter of 2000. On November 27, 2000, the NHPUC filed a petition for writ of certiorari with the United States Supreme Court. On February 20, 2001, the Supreme Court denied the petition for writ of certiorari, thus leaving the Court of Appeals approval of the permanent injunction intact.

In the third quarter of 2001, Management determined that Connecticut Valley qualifies for the application of SFAS No. 71, based on the favorable Court of Appeals decision of July 25, 2000, subsequent denial of the NHPUC's petition on February 20, 2001 and other regulatory developments in New Hampshire. The application of SFAS No. 71 resulted in an extraordinary charge of $0.2 million.

NOTE 13 – COMMITMENTS AND CONTINGENCIES

Nuclear Investments The Company has investments in three nuclear generating companies including Maine Yankee, Connecticut Yankee and Yankee Atomic, all of which are permanently shut down, and is responsible for paying its entitlement percentage of 2, 2 and 3.5 percent, respectively. See Note 2 – Investments in Affiliates for additional information. The Company is also responsible for its 1.7303 joint-ownership percentage of decommissioning costs for Millstone Unit #3.

On July 31, 2002, the Vermont Yankee plant was sold to Entergy. The Company had a 33.23 percent equity interest in the plant at the time of the sale and continues to have a 33.23 percent equity interest in VYNPC, a Vermont-based corporation, which administers the purchased power contracts among the former plant owners and Entergy. The Company no longer bears the operating costs and risks associated with running the plant or the costs and risks associated with the eventual decommissioning of the plant.

Nuclear Insurance The Price-Anderson Act ("Act") currently limits public liability from a single incident at a nuclear power plant to $9.5 billion. Beyond that, a licensee is indemnified under the Act, but subject to congressional approval. The first $200 million of liability coverage is the maximum provided by private insurance. The Secondary Financial Protection Program is a retrospective insurance plan providing additional coverage up to $9.3 billion per incident by assessing $88.1 million against each of the 106 reactor units that are currently subject to the Program in the United States, limited to a maximum assessment of $10 million per incident per nuclear unit in any one year. The maximum assessment is adjusted at least every five years to reflect inflation. The Act has been renewed since it was first enacted in 1957. The Act expired in August 2002; negotiations on a 15-year reauthorization of the Act are ongoing and require approval by the full House and Senate before taking effect. Existing commercial nuclear power plants are "grandfathered" under the most recent reauthorization of the law. Currently the Company could become liable for an aggregate of approximately $0.9 million of such maximum assessment per incident per year.

Hydro-Quebec The Company is purchasing varying amounts of power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract through 2016. The VJO includes a group of Vermont electric companies and municipal utilities, of which the Company is a participant. Related contracts were negotiated between the Company and Hydro-Quebec, which in effect altered the terms and conditions contained in the original contract by reducing the overall power requirements and related costs.

There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the balance of the VJO participants, including the Company, will "step-up" to the defaulting party's share on a pro rata basis. As of December 31, 2002, the Company's obligation is approximately 46 percent of the total VJO Power Contract through 2016, which translates to approximately $800 million, on a nominal basis, to the Company. The average annual amount of capacity that the Company will purchase from January 1, 2003 through October 31, 2012 is approximately 143 MW, with lesser amounts purchased through October 31, 2016.

In the early phase of the VJO Power Contract, two sellback contracts were negotiated, the first delaying the purchase of 25 MW of capacity and associated energy, the second reducing the net purchase of Hydro-Quebec power through 1996. In 1994, the Company negotiated a third sellback arrangement whereby the Company received an effective discount on up to 70 MW of capacity starting in November 1995 for the 1996 contract year (declining to 30 MW in the 1999 contract year). In exchange for this sellback, Hydro-Quebec has the right upon four years' written notice, to reduce capacity deliveries by up to 50 MW beginning as early as 2007 until 2015. This option includes the use of a like amount of the Company's Phase I/II facility rights. Hydro-Quebec can also exercise an option, upon one year's written notice, to curtail energy deliveries from an annual load factor of 75 to 50 percent due to adverse hydraulic conditions in Quebec. This can be exercised five times through October 2015. The third sellback arrangement is a derivative under SFAS No. 133. On April 11, 2001, the PSB approved an Accounting Order that requires that the contract's fair value be deferred on the balance sheet as either a deferred asset or liability. At December 31, 2002, this derivative had an estimated fair value of approximately a $0.7 million unrealized loss. The estimated fair value is based on quoted market information where available and appropriate modeling methodologies.

In February 1996, the Company reached an agreement with Hydro-Quebec that lowered the 1997 cost of power by $5.8 million. As part of this agreement, the Company made 54 MW of Phase I/II capacity available to Hydro-Quebec for its use to deliver an existing Firm Energy Contract or jointly marketed energy contracts to buyers in NEPOOL during the period from July 1, 1996 through June 30, 2001.

Under the VJO Power Contract, the VJO can elect to change the annual load factor from 75 percent to between 70 and 80 percent five times through 2020, while Hydro-Quebec can elect to reduce the load factor to not less than 65 percent three times during the same period of time (the VJO contract runs through 2020, however, the Company's schedules related to the contract end in 2016). The VJO has made three out of five elections to date, while Hydro-Quebec made its first election for the contract year beginning November 1, 2001 and the VJO elected to push the start of the 65 percent load factor to November 1, 2002.

The Company's estimated cost of energy and capacity under the existing contracts with Hydro-Quebec at a 75 percent load factor are expected to be $57.7 million, $61.2 million, $61.9 million, $62.5 million and $62.9 million for the years 2003 through 2007, respectively. See Note 12 – Retail Rates for discussion of Hydro-Quebec ice storm arbitration.

A summary of the Hydro-Quebec contracts including average annual projected charges for the years indicated, follows (dollars in thousands, except per kWh amounts):

	2002	Estimated Average 2003 – 2012	Estimated Average 2013 – 2016
Annual Capacity Acquired	**142.8MW**	143MW	(a)
Minimum Energy Purchase – annual load factor	**75%**	75%	75%
Energy Charge	**$23,937**	$28,118	$20,637
Capacity Charge	**$35,245**	$34,721	$21,550
Total Energy and Capacity Charge	**$59,182**	$62,839	$42,187
Average Cost per kWh	**$0.066**	$0.068	$0.073

(a) The Annual Capacity Acquired in MWs is approximately 115, 115, 100 and 19 for 2013 through 2016, respectively.

Independent Power Producers The Company purchases power from a number of Independent Power Producers ("IPPs") who own qualifying facilities under the Public Utility Regulatory Policies Act of 1978. These qualifying facilities produce energy using hydroelectric, biomass and refuse-burning generation. The majority of these purchases are made from a state-appointed purchasing agent who purchases and redistributes the power to all Vermont utilities pursuant to PSB Rule 4.100. For the 12 months ended December 31, 2002, the Company received 198,371 mWh under these long-term contracts, representing approximately 7.6 percent and 15 percent of the Company's total mWh purchases and related purchased power expense for the period, respectively. The total mWh received under these contracts includes 145,572 mWh allocated by the Purchasing Agent, VEPP Inc., and 36,675 mWh purchased by Connecticut Valley from a waste-to-energy electric generating facility owned by Wheelabrator Claremont Company, L.P. The Company's estimated purchases from IPPs are expected to be $22.5 million, $22.8 million, $22.3 million, $22.8 million and $21.1 million for the years 2003 through 2007, respectively.

On August 3, 1999, the Company, GMP, Citizens Utilities and all of Vermont's 15 municipal utilities filed a petition with the PSB requesting modification of the contracts between the IPPs and the state-appointed purchasing agent. The petition outlined seven specific elements that, if implemented, would reduce purchased power costs and reform these contracts for the benefit of consumers. On September 3, 1999, the PSB opened a formal investigation in Docket No. 6270 regarding these contracts as requested by the Petition. Shortly thereafter, Citizens Utilities, Hardwick Electric Department and Burlington Electric Department notified the PSB that they were withdrawing from the Petition but would participate in the case as non-moving parties. In a separate action before the Chittenden County Superior Court brought by several IPP owners, GMP's full participation in this PSB proceeding was enjoined and that injunction has since been appealed to and affirmed by the Vermont Supreme Court.

The Company participated in various legal proceedings and regulatory filings related to the Docket throughout 2000 and 2001. On January 28, 2002, the Petitioners and the IPPs filed a Memorandum of Understanding with the PSB, which, if approved, would establish a comprehensive settlement to the issues in Docket No. 6270 including: 1) power cost reductions nominally worth approximately $11 million to $14 million over 10 years based on an assumed start of January 2002; 2) the agreement of the IPPs to support efforts before the Vermont General Assembly and the PSB to authorize securitization and to negotiate for the buy-out and buy-down of the IPP contracts with the goal of achieving additional power cost savings; and 3) a global resolution of various related issues.

Efforts before the 2002 Vermont General Assembly resulted in the enactment of Act 145. Through this legislation, the state approved the use of securitization to buy-down or buy-out IPP contracts, and created a new state entity to issue bonds for that purpose.

On May 1 and 2, 2002, Technical Hearings were held before the PSB to consider the Memorandum of Understanding. At the hearings, certain of the non-petitioning Vermont utilities and the DPS argued that all Vermont electric utility customers should be permitted to share in the benefits arising under the Memorandum of Understanding. Subject to this and other conditions, the DPS argued that the Memorandum of Understanding should be approved.

On December 9, 2002, the Hearing Officer served a Proposal for Decision to all parties in the case to provide them an opportunity to submit comments and request oral arguments before the PSB. In the Proposal for Decision, the Hearing Officer recommended that the PSB approve the Memorandum of Understanding, but only with specific changes. Most notable is a requirement that the utility benefits arising under the Memorandum of Understanding are shared proportionally among all Vermont electric utilities and that the non-petitioning Vermont utilities reimburse the Petitioners for each utility's proportionate share of the litigation expense.

On January 6, 2003, the Petitioners filed a Stipulation with the DPS and certain non-petitioning Vermont utilities agreeing to the terms and conditions of the Proposal for Decision with minor corrections that the Stipulation parties requested be made in the final order on the Memorandum of Understanding. On January 7, 2003, the IPPs and the Petitioners separately made filings with the PSB confirming the Memorandum of Understanding will bind them as modified by the conditions contained in the Proposal for Decision. On January 13, 2003, the Hearing Officer submitted the Proposal for Decision, with the Stipulation parties' minor corrections, to the PSB for approval.

On January 15, 2003, the PSB issued an Order approving the Hearing Officer's Proposal for Decision. When implemented in accordance with the Order, the Memorandum of Understanding will reduce the cost of power purchased from the IPPs for all Vermont electric utilities. In accordance with the Order, the benefits achieved through implementation of the agreements approved as part of the Memorandum of Understanding will be delivered to and for the benefit of each Vermont utility's ratepayers.

Joint-ownership The Company's ownership interests in jointly owned generating and transmission facilities are set forth in the following table and are recorded in the Company's Consolidated Balance Sheets (dollars in thousands):

	Fuel Type	Ownership	In Service Date	MW Entitlement	December 31 2002	December 31 2001
Wyman #4	Oil	1.78%	1978	11.0	$3,347	$3,347
Joseph C. McNeil	Various	20.00%	1984	10.6	15,453	15,365
Millstone Unit #3	Nuclear	1.73%	1986	20.0	76,143	76,143
Highgate Transmission Facility		47.35%	1985	n/a	14,167	14,086
					109,110	108,941
Accumulated depreciation					49,549	47,049
					$59,561	$61,892

The Company's share of operating expenses for these facilities is included in the corresponding operating accounts on the Consolidated Statements of Income. Each participant in these facilities must provide for its financing.

As a joint owner of the Millstone Unit #3 facility, in which Dominion Nuclear Corporation ("DNC") is the lead owner with approximately 93.47 percent of the plant joint-ownership, the Company is responsible for its share of nuclear decommissioning costs. The Company's contributions to the Millstone Unit #3 Trust Fund have ceased based on DNC's representation to various regulatory bodies that the Trust Fund, for its share of the plant, exceeded the Nuclear Regulatory Commission's minimum calculation required. The Company could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded.

Environmental The Company is an amalgamation of more than 100 predecessor companies. Those companies engaged in various operations and activities prior to being merged into the Company. At least two of these companies were involved in the production of gas from coal to sell and distribute to retail customers at four different locations. The Company discontinued these activities in the late 1940s or early 1950s. The coal gas manufacturers, other predecessor companies and the Company itself may have engaged in waste disposal activities which, while legal and consistent with commercially accepted practices at the time, may not meet modern standards and thus represent potential liability.

The Company is engaged in various operations and activities that subject it to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency ("EPA"). It is Company policy to comply with all environmental laws. The Company has implemented various procedures and internal controls to assess and assure compliance. If non-compliance is discovered, corrective action is taken. Based on these efforts and the oversight of those regulatory agencies having jurisdiction, the Company believes it is in compliance, in all material respects, with all pertinent environmental laws and regulations. Below is a brief discussion of the Company's environmental sites.

Cleveland Avenue Property The Company's Cleveland Avenue property, located in the City of Rutland, Vermont, was a site where one of its predecessors operated a coal-gasification facility and later the Company sited various operations functions. Due to the presence of coal tar deposits and Polychlorinated Biphenyl ("PCB") contamination and uncertainties as to potential off-site migration of those contaminants, the Company conducted studies in the late 1980s and early 1990s to determine the magnitude and extent of the contamination. Site investigation has continued over the last several years and the Company continues to work with the State of Vermont in a joint effort to develop a mutually acceptable solution.

Brattleboro Manufactured Gas Facility From the early to late 1940s, the Company owned and operated a manufactured gas facility in Brattleboro, Vermont. The Company commissioned an environmental site assessment in late 1999 upon request by the State of New Hampshire. In October 2001, the Company received a Certificate of No Further Action from the State of New Hampshire; however, the State reserves the right to require additional investigation or remedial measures, if necessary. On January 17, 2002, the Company received a letter from the Vermont Agency of Natural Resources notifying the Company that its corrective action plan for the site was approved. The corrective action plan is now in place, including periodic groundwater monitoring and institutional controls.

Dover, New Hampshire, Manufactured Gas Facility In late 1999, the Company was contacted by PSNH with respect to this site. PSNH alleged the Company was partially liable for remediation of the site. PSNH's allegation was premised on the fact that prior to PSNH's purchase of the facility, it was operated by Twin State Gas and Electric ("Twin State").

Twin State merged with the Company on the same day the facility was sold to PSNH. The Company and PSNH agreed to and have participated in non-binding mediation regarding liability.

In December 2000, PSNH submitted a work plan to the State of New Hampshire for further investigation of this site. The Company agreed, with reservations, to participate on a limited basis in the development and completion of the work plan since the State of New Hampshire considers the Company, along with others, as potentially responsible parties at the site. The Company, PSNH and Keyspan Energy hired a contractor, which completed the fieldwork in October 2001. A report was published and submitted to the State of New Hampshire in August 2002.

Having previously agreed to non-binding mediation, a mediator on the issue of liability was chosen in April 2001 and the first phase of mediation, "Phase I", concluded on July 18, 2001. Without admitting liability, both the Company and PSNH agreed to participate in the site remediation for those years that Twin State and PSNH were responsible. On October 30 and 31, 2001, the Company and PSNH met with the other potentially responsible parties in a "Phase II" mediation process. The subject of the Phase II mediation was the liability of other potentially responsible parties at the site, in particular those that owned the property after Twin State and PSNH. The Phase II mediation process did not achieve the goal of a general agreement on liability between the participants.

In June 2002, the Company reached a settlement agreement with PSNH regarding the Dover site in which neither party admitted liability or the allegations made against them by the New Hampshire Department of Environmental Services. Under the settlement agreement, the Company agreed to transfer and assign to PSNH certain liabilities it may have related to the site, in exchange for an agreed upon amount to be paid by the Company to PSNH for its ongoing share of Qualified Site Liability Costs. Based on the terms of the Dover settlement agreement reached with PSNH, the Company reversed $1.7 million of its environmental reserves in the second quarter of 2002.

As of December 31, 2002 and 2001, reserves of $7.5 million and $9.2 million, respectively, are recorded on the Consolidated Balance Sheets representing management's best estimate of the costs to remediate the sites discussed above. The Company is not subject to any pending or threatened litigation with respect to any other sites that have the potential for causing the Company to incur material remediation expenses, nor has the EPA or any other federal or state agency sought contribution from the Company for the study or remediation of any such sites.

Dividend restrictions The indentures relating to long-term debt, the Articles of Association and a covenant contained in the Reimbursement Agreements to the letters of credit, supporting the Company's tax exempt revenue bonds, contain certain restrictions on the payment of cash dividends on capital stock. Under the most restrictive of such provisions, approximately $65.5 million of retained earnings was not subject to dividend restriction at December 31, 2002.

Under the Company's Second Mortgage Indenture, certain restrictions on the payment of dividends would become effective if the Company's Second Mortgage Bonds are rated below investment grade. Under the most restrictive of these provisions, all except approximately $3 million of retained earnings would be subject to dividend restrictions at December 31, 2002. In addition, Catamount has debt instruments in place that restrict the amount of dividends on capital stock that they are able to pay.

Leases and support agreements The Company participated with other electric utilities in the construction of the Phase I Hydro-Quebec interconnection transmission facilities in northeastern Vermont, which were completed at a total cost of approximately $140 million. Under a support agreement relating to the Company's participation in the facilities, the Company is obligated to pay its 4.55 percent share of Phase I Hydro-Quebec capital costs over a 20-year recovery period through and including 2006. The Company also participated in the construction of Phase II Hydro-Quebec transmission facilities constructed throughout New England, which were completed at a total cost of approximately $487 million. Under a similar support agreement, the New England participants, including the Company, have contracted to pay their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. The Company is obligated to pay its 5.132 percent share of Phase II Hydro-Quebec capital costs over a 25-year recovery period through and including 2015. These support agreements meet the capital lease accounting requirements under SFAS No. 13, *Accounting for Leases*. All costs under these support agreements are recorded as purchased transmission expense in accordance with the Company's ratemaking policies. Future expected payments will range from approximately $3.9 million to $2.7 million for each year from 2003 through 2015 and will decline thereafter.

Rental commitments of the Company under non-cancelable leases as of December 31, 2002 are considered minimal, as the majority of the Company's leases are cancelable after one year from lease inception. Total rental expense included in the determination of net income, consisting principally of vehicle and equipment rentals, was approximately $4.5 million for 2002 and $4.2 million for each year 2001 and 2000.

Catamount Catamount entered into Indemnity Agreements, dated December 21, 1995, with Amerada Hess Corporation (formerly Eastern Energy Marketing, Inc.), related to its investments in Rupert Cogeneration Partners Ltd. and Glenns Ferry Cogeneration Partners Ltd. (collectively the "Partnerships"). Amerada Hess supplies the Partnerships with natural gas and related transportation pursuant to the Gas Services Agreements ("Gas Agreements"). Amerada Hess also entered into a natural gas supply agreement with Talisman Energy Inc. to supply the natural gas for the Partnerships. Under the Firm Energy Supply Agreements between the Partnerships and Idaho Power Company ("IPCO"), Amerada Hess provided certain security interests to IPCO for liquidated damages in the event that non-performance by Amerada Hess or Talisman Energy Inc. under the Gas Agreements causes the Partnerships to permanently curtail electric power sales to IPCO. Pursuant to the Indemnity Agreements, Catamount will indemnify Amerada Hess for up to 50 percent of the liquidated damages associated with non-performance under the Gas Agreements. The liquidated damages are calculated based on the terms of the Firm Energy Supply Agreements. Catamount's estimated range of exposure under the Indemnity Agreements is between $0.8 million and $5.6 million, depending on the year a liquidated damage claim is made.

Catamount's wholly owned subsidiary, Equinox Vermont Corporation ("Equinox"), verbally agreed to indemnify Tractabel Power, Inc. for up to 33 percent of the cost in the event that the price of fuel for Ryegate Associates (the "Partnership") rises above the price cap guaranteed by Tractebel, Inc. to the Partnership's lender. The verbal indemnity is non-recourse to Catamount.

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

Change of control The Company has management continuity agreements with certain officers that become operative upon a change in control of the Company. Potential severance expense under the agreements varies over time depending on several factors, including the specific plan for individual officers and officers' compensation and age at the time of the change of control.

NOTE 14 – SEGMENT REPORTING

The Company's reportable operating segments include: **Central Vermont Public Service Corporation ("CV")**, which engages in the purchase, production, transmission, distribution and sale of electricity in Vermont; **Connecticut Valley Electric Company Inc. ("CVEC")**, which distributes and sells electricity in parts of New Hampshire. CVEC, while managed on an integrated basis with CV, is presented separately because of its separate and distinct regulatory jurisdiction; **Catamount Energy Corporation ("Catamount")**, which invests in non-regulated, energy generation projects in the United States and Western Europe; **Eversant Corporation ("Eversant")**, which engages in the sale or rental of electric water heaters through a subsidiary, SmartEnergy Water Heating Services, Inc. to customers in Vermont and New Hampshire; and **Other** includes operating segments below the quantitative threshold for separate disclosure. These operating segments include C. V. Realty, Inc., a real estate company whose purpose is to own, acquire, buy, sell and lease real and personal property and interests therein related to the utility business, and Catamount Energy Resources Corporation which was formed for the purpose of holding the Company's subsidiaries that invest in non-regulated business opportunities.

The accounting policies of the operating segments are the same as those described in the summary of significant accounting policies. Intersegment revenues include sales of purchased power to CVEC and revenues for support services, including allocations of building costs for space rental, software systems and equipment, to CVEC, Catamount and Eversant.

The intersegment sales and services for each jurisdiction are based on actual rates or current costs. The Company evaluates performance based on stand-alone operating segment net income. Financial information by industry segment for 2002, 2001 and 2000 is as follows (dollars in thousands):

2002	CV VT	CVEC NH	Catamount	Eversant	Other	Reclassification and Consolidating Entries	Consolidated
Revenues from external customers	$283,146	$20,242	$2,567	$1,988	$15	$4,569	$303,389
Intersegment revenues	11,366	-	-	-	-	11,366	-
Depreciation and other (1)	13,426	349	77	204	3	284	13,775
Asset impairment charges (2)	-	-	2,774	-	-	-	2,774
Operating income tax expense (benefit)	11,993	241	1,376	(332)	16	1,060	12,234
Operating income (loss)	26,719	352	(6,551)	(1,041)	27	(7,443)	26,949
Equity income - utility affiliates (3)	3,909	-	-	-	-	-	3,909
Equity income - non-utility affiliates (2)	-	-	11,651	-	-	11,651	-
Other income (expenses), net	(436)	6	(1,012)	(68)	49	(2,883)	1,422
Interest expense, net	11,705	209	1,171	(336)	-	236	12,513
Net income (loss)	18,522	149	1,541	(472)	27	-	19,767
Investments in affiliates	23,716	-	-	-	-	-	23,716
Total assets	445,412	12,411	60,743	3,177	10,362	5,240	526,865
Capital expenditures	13,664	557	94	127	-	-	14,442
2001							
Revenues from external customers	$281,745	$20,738	$504	$2,397	$7	$2,915	$302,476
Intersegment revenues	11,297	-	-	-	-	11,297	-
Depreciation and other (1)	15,458	475	57	315	3	375	15,933
Regulatory asset write-off (4)	9,000	-	-	-	-	-	9,000
Reversal of estimated loss on power contracts (5)	2,934	-	-	-	-	-	2,934
Asset impairment charges (2)	-	-	8,905	-	-	-	8,905
Investment write-down (2)	-	-	-	1,963	-	-	1,963
Operating income tax expense (benefit)	11,044	427	1,793	(1,468)	6	330	11,472
Operating income (loss)	26,468	1,063	(6,003)	(577)	9	(6,429)	27,389
Equity income - utility affiliates (3)	2,669	-	-	-	-	-	2,669
Equity income - non-utility affiliates (2)	-	-	6,079	-	-	6,079	-
Other income (expenses), net	(4,255)	1	(7,767)	315	18	2,022	(13,710)
Interest expense, net	12,324	376	1,009	570	-	401	13,878
Net income (loss)	12,671	506	(8,700)	(2,079)	9	-	2,407
Investments in affiliates	23,823	-	-	-	-	-	23,823
Total assets	449,820	12,191	58,266	4,531	321	3,455	521,674
Capital expenditures	15,945	407	85	116	-	-	16,553
2000							
Revenues from external customers	$310,388	$23,544	$1,145	$3,585	$7	$4,743	$333,926
Intersegment revenues	11,942	-	-	-	-	11,942	-
Depreciation and other (1)	21,646	495	63	277	3	343	22,141
Reversal of estimated loss on power contracts (5)	-	1,202	-	-	-	-	1,202
Purchased power disallowance (5)	(2,934)	-	-	-	-	-	(2,934)
Reversal of purchased power disallowance (5)	11,436	-	-	-	-	-	11,436
Operating income tax expense (benefit)	7,506	1,528	685	(1,583)	9	(889)	9,034
Operating income (loss)	21,489	3,173	(3,983)	1,125	13	(2,762)	24,579
Equity income - utility affiliates (3)	3,268	-	-	-	-	-	3,268
Equity income (loss) - non-utility affiliates (2)	-	-	4,957	(3,734)	-	1,223	-
Other income (expenses), net	5,422	17	531	(26)	25	1,474	4,495
Interest expense, net	13,510	326	814	135	-	347	14,438
Net income (loss)	16,807	2,865	690	(2,332)	13	-	18,043
Investments in affiliates	24,527	-	-	-	-	-	24,527
Total assets	478,067	12,203	48,688	6,470	313	5,903	539,838
Capital expenditures	14,379	545	44	-	-	-	14,968

(1) Includes net deferral and amortization of nuclear replacement energy and maintenance costs (included in Purchased power) and amortization of conservation and load management costs (included in Other operation expenses) in the accompanying Consolidated Statements of Income.

(2) See Note 3 herein for CV's investment in non-utility affiliates.

(3) See Note 2 herein for CV's investments in affiliates.

(4) See Note 12 herein for CV's retail rates.

(5) Included in Purchased power in the accompanying Consolidated Statements of Income.

NOTE 15 – UNAUDITED QUARTERLY FINANCIAL INFORMATION

The following quarterly financial information is unaudited and includes all adjustments consisting of normal recurring accruals which are, in the opinion of Management, necessary for a fair statement of results of operations for such periods (dollars in thousands, except per share amounts):

	Quarter Ended				12-Months
2002	March	June	September	December	Ended
Operating revenues	$76,475	$71,903	$75,733	$79,278	$303,389
Operating income	$7,159	$5,802	$9,170	$4,818	$26,949
Net income	$4,785	$3,975	$5,855	$5,152	$19,767
Earnings per share of common stock – basic	$0.37	$0.31	$0.47	$0.41	$1.56
Earnings per share of common stock – diluted	$0.37	$0.30	$0.46	$0.40	$1.53
2001					
Operating revenues	$78,032	$73,882	$75,135	$75,427	$302,476
Operating income	$6,126	$7,519	$7,606	$6,138	$27,389
Net income (loss)	$3,897	$326	$3,565	$(5,382)	$2,407
Earnings per share of common stock – basic and diluted	$0.30	$(0.01)	$0.27	$(0.50)	$0.06

MANAGEMENT REPORT ON RESPONSIBILITY FOR FINANCIAL INFORMATION

Responsibility for the integrity and objectivity of the consolidated financial statements presented in this Annual Report rests within the management of Central Vermont Public Service Corporation. The accompanying Consolidated Financial Statements have been prepared in conformity with generally accepted accounting principles and the accounting policies and principles prescribed by the Vermont PSB and the FERC. The Consolidated Financial Statements include amounts that are based on management's best estimates and judgements. Management also prepared the other financial information presented in this Annual Report and is responsible for its accuracy and consistency with the Consolidated Financial Statements.

The Company has established and maintains an accounting system and a related system of internal accounting controls directed toward safeguarding assets and providing accurate and reliable financial information. An integral part of the system of internal accounting controls is an internal audit function designed to monitor compliance with the Company's accounting and financial reporting policies and procedures. Management believes that the Company's accounting system and related system of internal accounting controls are adequate to achieve the objectives discussed above.

Deloitte & Touche LLP, independent public accountants, has been retained to audit the Company's Consolidated Financial Statements. The accompanying report of independent public accountants is based on their audit conducted in accordance with generally accepted auditing standards.

The Audit Committee of the Board of Directors is composed solely of outside directors, and is responsible for recommending to the Board of Directors the selection of the independent public accounting firm to be retained in the audit of the Company's Consolidated Financial Statements. The Audit Committee meets periodically and privately with the independent public accountants, with the internal auditors, as well as Company management, to review accounting, auditing, internal accounting controls and financial reporting matters.

Robert H. Young

Robert H. Young
President and Chief Executive Officer

Jean Gibson

Jean Gibson
Senior Vice President,
Chief Financial Officer and Treasurer

COMMON STOCK PRICES AND DIVIDENDS

2002	High	Low	Dividends Per Share
1st quarter	$18.38	$16.00	$.22
2nd quarter	19.66	16.41	.22
3rd quarter	18.20	15.69	.22
4th quarter	18.87	16.80	.22
2001			
1st quarter	$17.00	$11.625	$.22
2nd quarter	19.64	15.25	.22
3rd quarter	18.99	15.50	.22
4th quarter	18.55	16.20	.22

SHAREHOLDER INFORMATION

Information regarding stock transfer, lost certificates, dividend checks, dividend reinvestment, optional cash investments, automatic monthly investments from bank accounts, and direct deposit of dividend payments may be directed to the transfer agent as noted below. Please include a reference to Central Vermont Public Service and a telephone number where you can be reached.

Registrar, Transfer Agent and Dividend Disbursing Agent for Common and Preferred Stocks:

EquiServe Trust Company
P.O. Box 43010
Providence, RI 02940-3010
1-800-736-3001
www.equiserve.com

You may also contact CVPS Shareholder Services at 1-800-354-2877, on the Internet at http://www.cvps.com, or by e-mail at shsvcs@cvps.com.

ANNUAL MEETING

The Annual Meeting of Shareholders is scheduled for 10 a.m. on Tuesday, May 6, 2003, at the Killington Grand Hotel & Conference Center, Killington Road, Killington, Vermont. Notice of the meeting and proxy statement and proxy will be mailed to holders of common stock.

DIVIDEND REINVESTMENT AND COMMON STOCK PURCHASE PLAN

Shareholders may reinvest dividends and make monthly cash investments of at least $100 and no more than $5,000 per month. Purchase of shares is optional, regardless of whether dividends are reinvested. This is not an offer to sell, nor a solicitation of an offer to buy, any securities. Any stock offering will be made only by prospectus. For further information, please contact EquiServe Trust Company at the address above.

COMMON STOCK LISTING

Central Vermont common stock is listed on the New York Stock Exchange under the trading symbol CV. Newspaper listings of stock transactions use the abbreviation CVtPS or CentlVtPS and the internet trading symbol is CV.

DIVIDENDS

All dividends paid by the company represent taxable income to shareholders for federal income tax purposes. No portion of the 2002 dividend was a return of capital.

Traditionally, the Board of Directors declares dividends to be payable on the 15th day of February, May, August, and November to shareholders of record on the last business day of the month prior to payment.

CREDIT RATINGS

The table below indicates ratings of the company's securities as of February 2003.

	Standard & Poor's	Fitch IBCA
Corporate Credit Rating	BBB-	N/A
First Mortgage Bonds	BBB+	BBB
Second Mortgage Bonds	BBB-	BBB-
Preferred Stock	BB	BB+

All of Central Vermont's ratings have a stable outlook.

FINANCIAL INFORMATION

We welcome inquiries from individuals and members of the financial community. Please direct your inquiries to:

Jean H. Gibson, Chief Financial Officer
Central Vermont Public Service
77 Grove Street
Rutland, VT 05701

FORM 10-K

The corporation will furnish, without charge, a copy of its most recent annual report to the Securities and Exchange Commission (Form 10-K) upon receipt of a written request. Please write:

Joseph M. Kraus, Secretary
Central Vermont Public Service
77 Grove Street
Rutland, VT 05701

Directors

Frederic H. Bertrand
(66)/1984/Chair of the Board, Central Vermont Public Service; Retired Chair of the Board and Chief Executive Officer, National Life Insurance Co., Montpelier, Vermont (1)(3)(4)

Robert L. Barnett
(62)/1996/Executive Vice President, Motorola Inc., Schaumburg, Illinois (Communications Equipment) (2)(4)

Rhonda L. Brooks
(50)/1996/President, R Brooks Advisors Inc., Pinehurst, North Carolina (Consulting Firm) (3)

Janice B. Case
(50)/2002/Former Senior Vice President, Energy Solutions, Florida Power Corporation, St. Petersburg, Florida (Electric Utility) (2)

Robert G. Clarke
(52)/1997/Chancellor of the Vermont State Colleges, Waterbury, Vermont (2)

Timothy S. Cobb
(61)/2000/Retired Chair, President and Chief Executive Officer, Salient 3 Communications Inc., Seneca, South Carolina (Design and Engineering of Electric Power Facilities) (3)

Luther F. Hackett
(69)/1979/President, Hackett, Valine & MacDonald Inc., Burlington, Vermont (Insurance) (1)(2)

George MacKenzie Jr.
(53)/2001/Former Executive Vice President and Chief Financial Officer, Glatfelter Company, York, Pennsylvania (Global Manufacturer of Specialty Papers and Engineered Products) (2)

Mary Alice McKenzie
(45)/1992/Vice President and General Counsel, Vermont State Colleges, Waterbury, Vermont (3)(4)

Janice L. Scites
(52)/1998/President, Scites Associates Inc., Basking Ridge, New Jersey (Technology and Business Consulting Firm) (3)

Herbert H. Tate
(49)/2001/Of-Counsel, Wolff & Samson, P.C. (Law Firm), West Orange, New Jersey (2)

Robert H. Young
(55)/1995/President and Chief Executive Officer, Central Vermont Public Service (1)

(1) Member of Executive Committee
(2) Member of Audit Committee
(3) Member of Compensation Committee
(4) Member of Nominating Committee

Officers

Robert H. Young
(55)/1987/President and Chief Executive Officer

Kent R. Brown
(57)/1996/Senior Vice President, Engineering and Operations

William J. Deehan
(50)/1985/Vice President, Transmission and Generation Planning and Regulatory Affairs

Joan F. Gamble
(45)/1989/Vice President, Strategic Change and Business Services

Jean H. Gibson
(46)/2002/SeniorVice President, Chief Financial Officer, and Treasurer

John J. Holtman
(46)/2000/Vice President and Controller

Joseph M. Kraus
(47)/1981/Senior Vice President, Customer Service, Secretary, and General Counsel

Robert E. Rogan
(43)/1998/Vice President, Public Affairs

Central Vermont Public Service

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