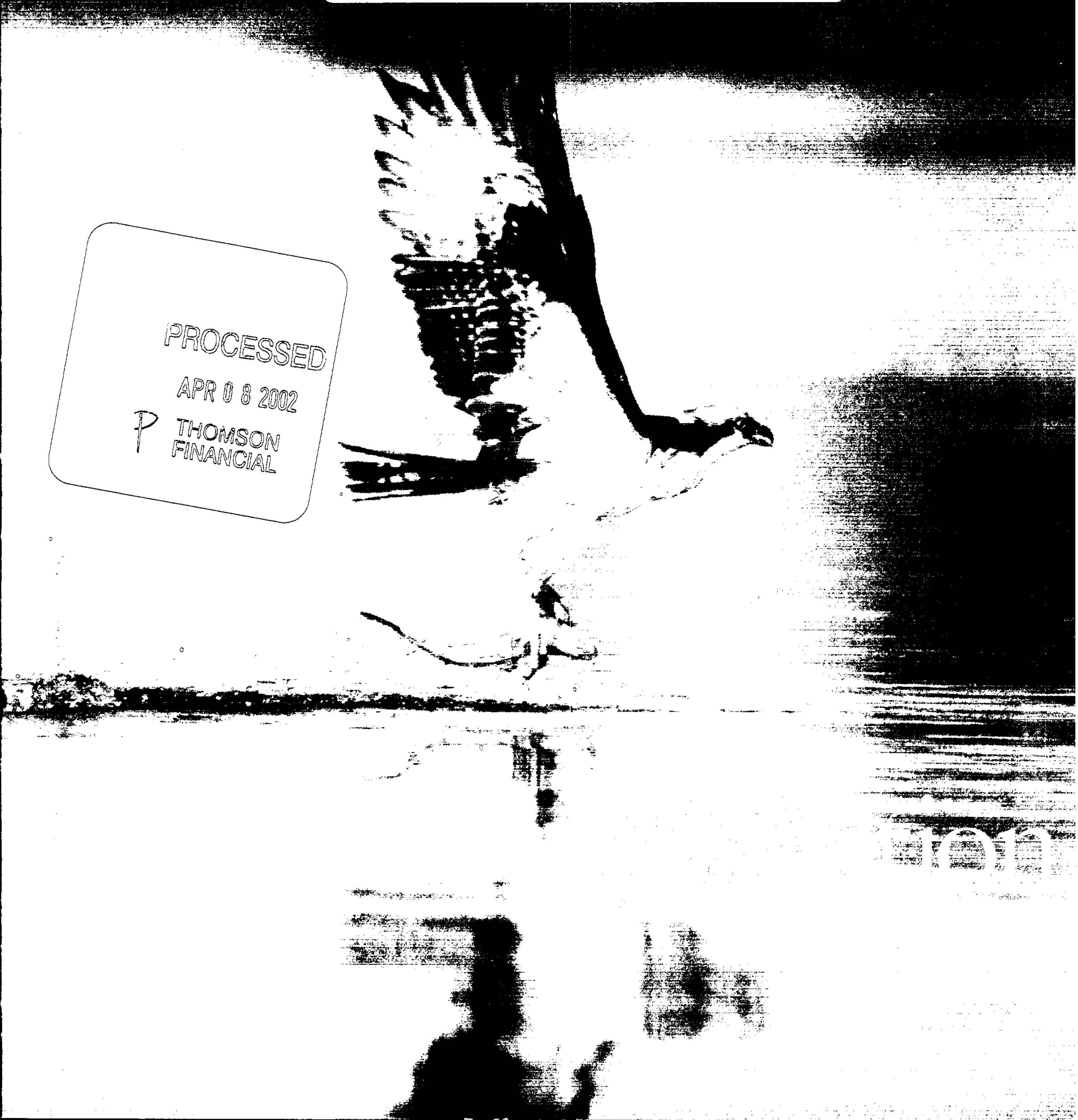
Central Vermont Public Service

ANNUAL REPORT 2001



Central Vermont Public Service is an independent energy and utility business based in Vermont with an expanding national and international presence.

We deliver energy services people count on and pursue growth by tailoring solutions that make our business partners more competitive.

Through the unified efforts of five strategic business units, we distribute, transmit and market electricity, invest in renewable, independent-power generation projects and pursue retail partnership opportunities. Our unregulated subsidiary and affiliate operations include:

- CATAMOUNT ENERGY, which invests primarily in wind energy projects, ranging in size from 10 to 150 megawatts, in the United States and Western Europe.
- EVERSANT, which markets energy-saving products and operates a rental water heater business.
- THE HOME SERVICE STORE (HSS), which provides homeowners and businesses access to home improvement and repair experts, with the added security of a satisfaction guarantee. HSS, an affiliate company, was originally part of Eversant, and is now an independent business.

The service territory of our core electric business is rural and mountainous: Each mile of distribution line serves an average of 19 customers, including commercial, industrial, and residential accounts. CVPS serves approximately 143,000 customers in Vermont. Through a subsidiary, Connecticut Valley Electric Company, we serve more than 10,000 customers in New Hampshire.

To Our Shareholders:

With a helping hand from CVPS, the majestic osprey featured on the cover of this report, once endangered in Vermont, is beginning to flourish again. In many ways, the osprey's journey parallels that of CVPS. Like the osprey, CVPS has overcome long odds to ensure its future. With steely determination, solid strategic thinking and good old-fashioned hard work, CVPS has emerged from years of financial and regulatory uncertainty. And like the osprey, our future is filled with promise.

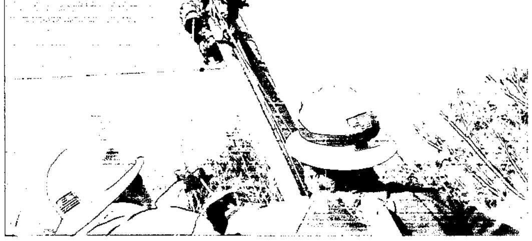
Faced with great challenges, the company overcame serious obstacles, and emerged stronger for the effort. While we would not choose to relive the events of the past 12 months, we are capitalizing on the lessons we have learned and the knowledge, skills and tools we have acquired, and are realizing our vision of distinguishing ourselves as a leader in the industry.

How that industry will look in the future remains unclear. Vermont, at least for now, has stepped back from the idea of opening the electric industry to retail power supply competition and customer choice. In New Hampshire, by contrast, state policymakers seek to open our Connecticut Valley Electric Company service territory to other power suppliers. We support that concept, but continue to pursue a fair transition to customer choice that recognizes our legitimate financial interests. Prospects for success were improved by a FERC administrative law judge's initial decision that CVPS is entitled to recover costs incurred by moving to retail competition.

Although the timing and path to retail choice remain uncertain, the actions we have taken in the past year have created a platform for our future success. In 2001, CVPS regained its financial stability through a hard-earned rate increase, a conclusion to the Hydro-Quebec cost-recovery dispute, and a pending agreement to sell Vermont Yankee Nuclear Power Station. A recent settlement that will reduce the costs of power from Vermont's independent power producers and a new three-year contract with the International Brotherhood of Electrical Workers, Local 300, also improved our outlook.

Stability came at the expense of meaningful current earnings for our shareholders, in part due to write-offs necessary to resolve the uncertainty over recovery of Hydro-Quebec power costs. Catamount Energy, meanwhile, repositioned itself to concentrate on the wind industry, with a new focus and new leadership. Catamount began to evaluate the sale and prospects of several existing assets, which prompted some write-downs. While these were difficult actions to take, they were carried out in the long-term best interests of the company, shareholders and customers. I am confident the short-term effects on earnings will be more than offset by the long-term benefits of having a stable, well-positioned company going forward.

In the second half of the year, we adopted a new business approach we call the Right Way to Work. This management technique has been implemented successfully by many companies across


the country, and was introduced to CVPS by Vermont Yankee Nuclear Power Corp., which adopted it several years ago, saving millions of dollars in operating costs.

I believe strongly that the Right Way to Work is the *best* way for CVPS to work, because employee participation and innovation play an integral role in its success. I have long said our employees are the company's strongest assets. Through their efforts to systematically reduce costs, improve work processes and remove unnecessary costs through the Right Way to Work, I anticipate producing tangible results by the end of 2002, which will continue into the future.

The Right Way to Work and the Vital Few — our most important goals — are key tools to help all employees focus on how we can best serve our customers and shareholders, and are detailed further in the body of this report.

CVPS's commitment to our customers was further strengthened by collaborating with state regulators to create new customer service standards in 2001. Serving Everyone with Reliability, Value and Excellence (SERVE) has become CVPS's motto for this new service quality program. Through SERVE, we are making unprecedented service guarantees to our customers.

We are also continuing to enhance our infrastructure through improvements to the transmission system and a system-wide pole and physical plant inventory, which we expect to complete this year. The data collected from the inventory will be used to augment customer service through full implementation of a centralized computer-aided system that will speed analysis of problems and hasten recovery.

With Hydro-Quebec cost disallowances, the court and FERC action related to Connecticut Valley Electric Company and numerous severe storms, the past several years have been difficult and turbulent ones for CVPS, its employees, and certainly for you, our shareholders. Our challenges have been numerous, yet you maintained your trust and confidence in our abilities, and for that I thank you.

I would also like to assure you that your trust has been earned. Financial rating agencies acknowledged CVPS's solid financial footing with a stable ratings outlook in 2001, and the markets recognized our efforts with a significant increase in our stock price. Despite that recognition, we are not content with our progress to date.

We are building our company's future on a foundation of unmatched breadth and depth. We now have the capacity to take to action all that we have been so determined to achieve, along with the knowledge, purpose and optimism to fuel that determination. In the coming year, we will remain committed to our goals, and I look forward to demonstrating how that commitment is transformed into the measurable progress and prosperity I am confident we will achieve.

Sincerely,

Robert H. Young

Robert H. Young
President and Chief Executive Officer

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RICHARD SOMERS
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POLLY GAUDETTE
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2001

FINANCIAL *(dollars in thousands)*	2001	% change	2000	% change	1999
Revenues	$302,476	(9.4)	$333,926	(20.5)	$419,815
Earnings Available for Common	$711	(95.6)	$16,264	10.5	$14,722
Construction/Demand-side Management Expenditures	$17,057	5.9	$16,104	2.8	$15,671
Net Utility Plant	$308,629	(0.8)	$310,976	(1.2)	$314,732
Total Capitalization[1]	$388,550	0.4	$386,997	(2.6)	$397,168
Average Number of Shares of Common Stock Outstanding	11,551,042	0.6	11,488,351	0.2	11,463,197
Common Equity/Percent of Total Capitalization[1]	47.4%		49.3%		46.3%
Return on Average Vermont Utility Common Equity	7.1%		9.9%		10.4%
Consolidated Return on Average Common Equity	0.4%		8.6%		7.9%

PER SHARE OF COMMON STOCK					
Earnings Per Share of Common Stock	$ .06	(95.77)	$1.42	10.9	$1.28
Dividends Paid	$ .88	—	$ .88	—	$ .88
Book Value (year-end)	$15.81	(4.6)	$16.57	3.2	$16.05
Catamount Energy	$(.75)	(1,350.0)	$ .06	(66.7)	$ .18
Eversant	$(.18)	10.0	$(.20)	20.0	$(.25)

OPERATING					
Retail Electric Sales (mWh)	2,324,099	(1.9)	2,369,164	1.2	2,340,440
System Peak (kW)	411,544	(4.3)	430,082	2.3	420,539
System Load Factor	69.5%		67.4%		69.2%
Degree Days (Rutland, Vermont)	7,133	(8.6)	7,802	3.9	7,506
Customers (year-end)	154,274	1.5	151,943	0.4	151,324
Shareholders	10,073	(0.6)	10,135	(6.7)	10,862

[1] *Includes short-term debt and current portion of long-term debt.*

Net Income for 2001 was $2.4 million, or $.06 per share of common stock, compared to net income of $18.0 million, or $1.42 per share, for 2000.

Excluding the following nonrecurring items, Central Vermont's (CV) consolidated after-tax earnings were $16.0 million, or $1.24 per share, for 2001 and $13.7 million, or $1.05 per share, for 2000.

(dollars in millions, except EPS)	**Favorable**	**(Unfavorable)**
2001:	**After-tax**	**EPS**
Write-off of certain regulatory assets as a result of the rate settlement effective July 1, 2001	$ (5.3)	$(0.46)
Asset impairment charges at Catamount during fourth quarter 2001 relating to four of its non-regulated generation projects[1]	(9.8)	(0.85)
Extraordinary charge at Connecticut Valley Electric Co. (CVEC) resulting from the application of FAS 71	(0.2)	(0.02)
Elimination of charges for the under-recovery of costs relating to the power contract with Hydro-Quebec	1.7	0.15
Totals for 2001	$(13.6)	$(1.18)
2000:		
Reversal of CVEC's provision for rate refund	$1.7	$0.14
Millstone Unit #3 settlement on July 27, 2000	3.2	0.28
Asset impairment charge at Catamount for its investment in Gauley River Hydro Project[1]	(0.6)	(0.05)
Totals for 2000	$4.3	$0.37

[1] *Affects non-regulated operations*

Utility Operations:

Other than the above nonrecurring items affecting utility operations, CV's utility operations were significantly affected during 2001 by the following:

- The 3.95% increase in Vermont retail rates, under a settlement agreement that went into effect on July 1, 2001, provided $2.9 million to earnings, or $0.25 per share. This rate increase also resolved the regulatory issues with the Hydro-Quebec power contract.
- Unit sales to CV's retail customers were lower than 2000 by 45,065 mWh, or 1.9%. This negatively affected earnings by $2.5 million, or $0.22 per share.
- Higher operating costs of $2.9 million after-tax, or $0.25 per share, were caused by higher service restoration costs related to storm activity and higher costs of employee benefits.
- Lower net power costs of $4.2 million after-tax, or $0.37 per share, were mostly due to reduced operating and decommissioning costs at Vermont Yankee.

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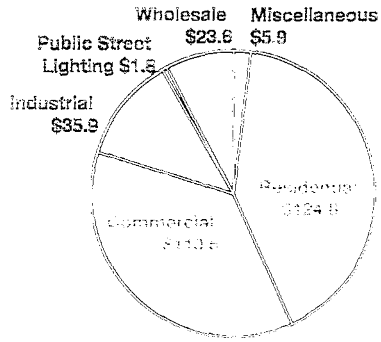
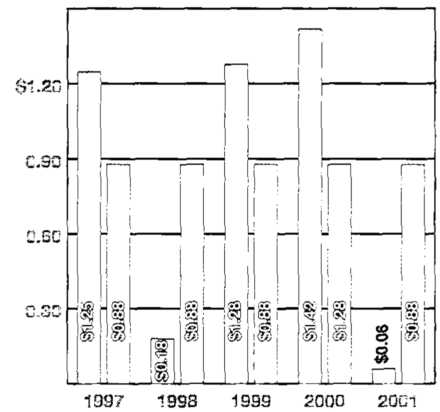
Revenue Analysis

($ in millions)



2001

Earnings Per Share and Dividends



Earnings Dividends

Electric Revenue and mWh Sales

Revenue from the sale of electricity to retail customers during 2001 of $273.0 million increased $2.4 million, or 0.9%, over 2000 revenue. A rate increase of 3.95%, effective on July 1, 2001, contributed $4.9 million, while a reduction of 1.9%, or 45,065 mWh sold, resulted in a decrease of $4.2 million in revenue. A change in the mix of sales contributed to a favorable pricing variance during 2001. The decline in retail mWh sales during 2001 was mostly attributable to milder winter weather and the slowdown in the economy affecting the company's industrial customers.

Revenue from sales to wholesale customers during 2001 was $23.6 million, which was less than 2000 by $30.0 million. This decrease was mostly caused by the discontinuation in the third quarter of 1999 of an alliance with Virginia Power to jointly supply wholesale power in the Northeast. Committed contract sales under this alliance ended in December 2000, and totaled $22.2 million for the year. Power costs related to the 2000 alliance revenues decreased by a similar amount.

Non-regulated Earnings

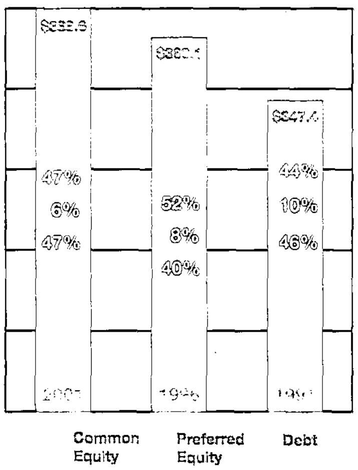
For 2001, our total non-regulated operations reported a loss of $10.8 million, or $0.93 per share, as compared to a loss of $1.6 million, or $0.14 per share, for 2000. Catamount and Eversant Corporation (Eversant, formerly SmartEnergy Services) and its subsidiaries make up our non-regulated operations.

Catamount experienced a loss of $8.7 million, or $0.75 per share, during 2001. As stated above, Catamount recorded an asset impairment charge of $9.8 million, or $0.85 per share of common stock. These charges related to four of its non-regulated generation projects. Two projects being held for sale (Gauley River Hydro and Fibrothetford) were written down to estimated sales value and issues of future viability affected two other projects (Glenns Ferry and Rupert cogeneration projects in Idaho).

Eversant recorded a loss of $2.1 million, or $0.18 per share, for 2001 compared to a 2000 loss of $2.3 million, or $0.20 per share. Eversant experienced a lower net loss from its affiliate, The Home Service Store (HSS), offset by higher business development costs, as well as an accrual for a potential income tax liability during 2001.

Capitalization Ratios*

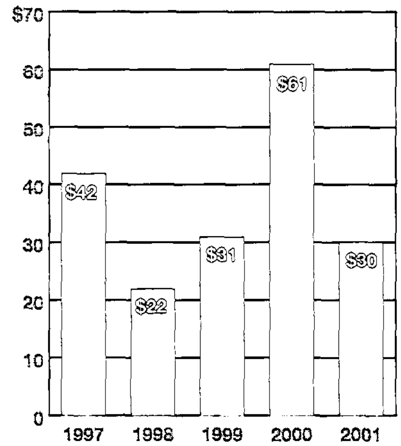
($ in millions)



*Year-end balances, include short-term debt and current portion of long-term debt.

Cash Flow from Operating Activities

($ in millions)



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ALEXANDER WIMETT
JAMES BURT
TRACY CONE
MALCOLM VAN ARSDALE IV
SHAWN MAGOON
JOHN NUCEDER
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LARRY SMITH
CAROL DENARDO
THEODORE OLENCKI JR
DAVID SALATINO
PHILIP SMITH
TONIA ERICKSON
TRACY ADAMS
ALAN BACCEI
JOHN GREENAN
CATHY PETRINI
KIMBERLY JONES
WENDY PERRY
JEFFREY MONDER
MICHAEL EZZO
MICHAEL EDSON
BEVERLY RIPLEY
ROLAND SMITH
HELEN BRUNO
DAVID FLORY
MATTHEW PENNINGTON
ROBERT HURST
JAMES LADABOUCHE
JANET COOLIDGE
THOMAS PITTS
SUSAN PARKER
NANCY YOUNG
KENNETH TURNER JR
TIMOTHY BRIGGS
JEREMY KELLETT
TIMOTHY HARTE
JANICE OVECKA
PETER KIRBACH
JASON KIBBEY
JUAN BUSTAMANTE
ROBERT LEWIS JR
JEFFREY PLOOF
DANIEL O'HARA
ERIK TOFT
KEITH BUDRO
SONDRA PHILBURT
DONALD BORDEAU
PENNY JONES
DUANE MARTIN
EUGENE KURANT
FRED HUGHES
THOMAS SMYRSKI
AL GELBAR
CLIFTON BRITCH JR
SONDRA STEVENS
WILLIAM STILLSON
RONALD MAJER
EDWARD SOLARI JR
C MULHOLLAND
CHARLES RICHARDS
BERNICE LENDWAY
WILLIAM LITTLER
GERRY CARRINGTON
DAVID BALLOU
KENNETH ROBERTS
SARA GOSINSKI
RHONDA NASH
LYNN KRATOCHVIL
GWEN RACINE
JOSHUA STARK
GENORA DOUGLAS
RICHARD COURCELLE
JOHN PULSIPHER JR
MATTHEW FREDETTE
JOHN CARROLL

Capitalization

CV's consolidated capital structure is weighted 47% debt, 6% preferred equity and 47% common equity as of December 31, 2001. The debt component reflects $4.0 million of first mortgage bonds redeemed under the sinking fund for the 9.97%, series HH bonds and $14.0 million of additional drawings by Catamount under its revolving credit facility with United Capital during 2001.

Liquidity

Cash generated from operations during 2001 was $30.2 million as compared to $60.9 million for 2000. Cash generation during 2001 was affected by a Vermont Yankee refueling outage (no outage during 2000), increased tax payments, working capital and the 3.95% rate increase effective July 1, while 2000 included the favorable impact of deseasonalized rates and the favorable Millstone Unit #3 settlement.

Credit Ratings

The following identifies CV's current ratings by Standard & Poor's and Fitch IBCA:

	Standard and Poor's	Fitch IBCA
Corporate credit rating	BBB-	N/A
First mortgage bonds	BBB+	BBB
Second mortgage bonds	BBB-	BBB-
Preferred stock	BB	BB+

During 2001, both Standard and Poor's and Fitch IBCA improved CV's credit ratings outlook to stable from negative due to the favorable resolution of the rate settlement effective July 1, 2001.

Taking to Action

Restore financial stability, improve customer service and build shareholder value. Focusing on these three objectives in 2001 enabled Central Vermont Public Service to build the foundation for significant changes, changes designed to transform CVPS from a good company into a great company. The 2001 CVPS Annual Report documents how the company created this opportunity, and how we intend to seize it.

To say 2001 was difficult does not do justice to the year past. From devastating snowstorms that wreaked unparalleled havoc on our systems, to write-offs related to the Hydro-Quebec power contract and Catamount Energy, 2001 brought real pain to Central Vermont Public Service.

Securing a rate case settlement that resolved the company's Hydro-Quebec contract issues and provided adequate base rates, concluding the ice storm arbitration and reaching agreement on the proposed sale of Vermont Yankee were difficult. But to quote Winston Churchill: "It is no use saying, 'We are doing our best.' You have got to succeed in doing what is necessary." Though painful, the company did what was necessary in 2001 to make CVPS more profitable for shareholders and more responsive than ever to our customers.

Restoring CVPS to financial stability has been our prime management objective for six years, and in 2001 we achieved this critical goal. We also began an introspective examination of how we work, a process that will help us become ever more efficient and able to provide exemplary service to our customers.

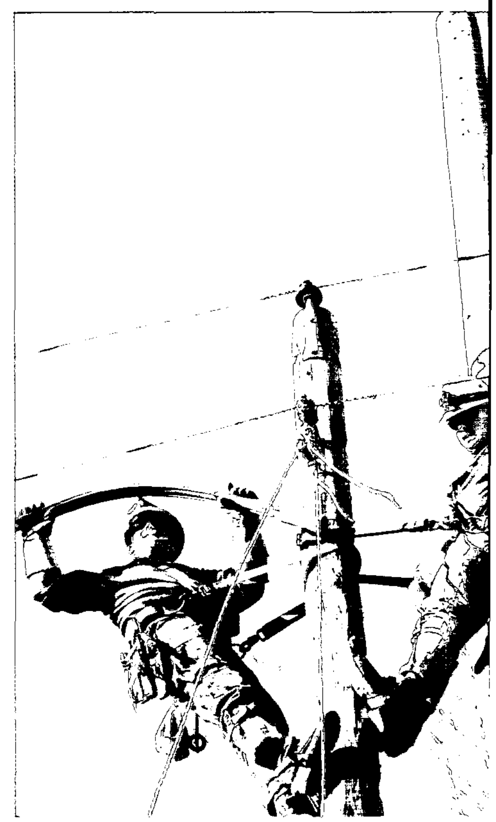
While the full effects of our work won't become clear until 2002 and beyond, the company is now better positioned than it has been in recent memory. We have set in place the tools necessary to take our vision for increased customer and shareholder value to action.

Restore Financial Stability

Hydro-Quebec Cost-Recovery Issue Resolved

In June, the Vermont Public Service Board approved a rate case settlement between CVPS and the Department of Public Service that removed the punishing uncertainty that plagued the company and industry for nearly six years. The board's approval permanently resolved the longstanding dispute over the 1991 power contract with Hydro-Quebec. More importantly, the settlement gives the company the opportunity to earn its allowed 11 percent rate of return, and to focus on customer service, value creation and work-process improvements aimed at reducing costs and boosting performance.

The settlement spurred a rebound in our stock price and CVPS's removal from negative outlook status by rating agencies. However, the order also required a $9 million pre-tax asset write-off as a final Hydro-Quebec penalty. While painful, the settlement was a fair resolution that provided benefits for our shareholders and our customers, and helped CVPS regain market confidence.



Above: Tim Bruso (left) and Dave Stevens (right) install safety equipment as they prepare to move a line to serve a new customer in Barnard. **Opposite:** Lineworker Steve Shortsleeves discusses final arrangements with a co-worker for service work in Chittenden.

COLLABORATIVE NEGOTIATIONS PRODUCE LABOR AGREEMENT

As members of the Labor-Management Group, Jim Genovesi, Kerry O'Hara, Kent Brown, Al Wilkinson, George Clain, Petrina LaPlaca and Jeff Lawrence helped maintain the positive atmosphere of trust that produced consecutive labor agreements approved on the first vote.

CVPS and the International Brotherhood of Electrical Workers, Local 300, successfully negotiated a new three-year labor agreement, which was ratified by the company's 224 union members on the first vote in late December.

Under the new contract, unionized employees — line workers, meter readers, mechanics, hydro station operators and related field workers — will receive a 3 percent raise in each of the next three years, while over the same period, their contributions for health-care coverage will increase from 7 to 20 percent of the cost.

Like its predecessor, the agreement was reached through a win-win approach focused on creatively solving problems jointly facing the union and the company as we work together to meet customer needs. This is a collaborative approach to negotiations that requires mutual respect and a willingness to clearly express desired outcomes at the outset.

This agreement between the company and the union further solidified our financial stability and our sense of shared responsibility to serve customers and add value for shareholders.

Taking a Hard Look at Costs

In order to earn our allowed return, the company's first task is to reduce our costs for 2002 and beyond, while ensuring a high level of service and reliability. The scope and immediacy of this challenge requires that we consult the experts – our employees. Employees are working closely with their supervisors, perhaps as never before, to identify savings, reduce budgets and stop doing unnecessary work. This is the first step in a new and ongoing effort to root out waste wherever we find it.

Hydro-Quebec Arbitration Case Settled

In July, CVPS, 14 other Vermont utilities and Hydro-Quebec announced the final settlement of a contract dispute stemming from HQ's failure to deliver power after the January 1998 ice storm. CVPS received $4.3 million of the $9 million Hydro-Quebec returned to Vermont utilities for services paid for but not provided.

The decision to settle followed a ruling by the arbitration panel that partially agreed with the case made by Vermont utilities and by HQ. Continuing the legal fight would have required years of additional, costly litigation with no guarantee of success. Instead, we secured a fair settlement that keeps the stable-priced HQ contract in place until 2016, ends the ice storm dispute, and signals the restoration of a strategic relationship important to Vermont and Quebec.

Vermont Yankee Sale Approval Sought

In August, CVPS and the other owners of Vermont Yankee Nuclear Power Station reached an agreement, through an auction conducted by JPMorgan, to sell the plant to Entergy Corporation for $180 million.

The proposed sale includes an agreement to continue to purchase power from the plant through 2012 at lower rates, which will save CVPS's customers an estimated $78 million. The agreement also includes a price adjuster to ensure Vermonters will benefit if the market price of power drops below the contract price, and will remove financial risks associated with operating and decommissioning the plant.

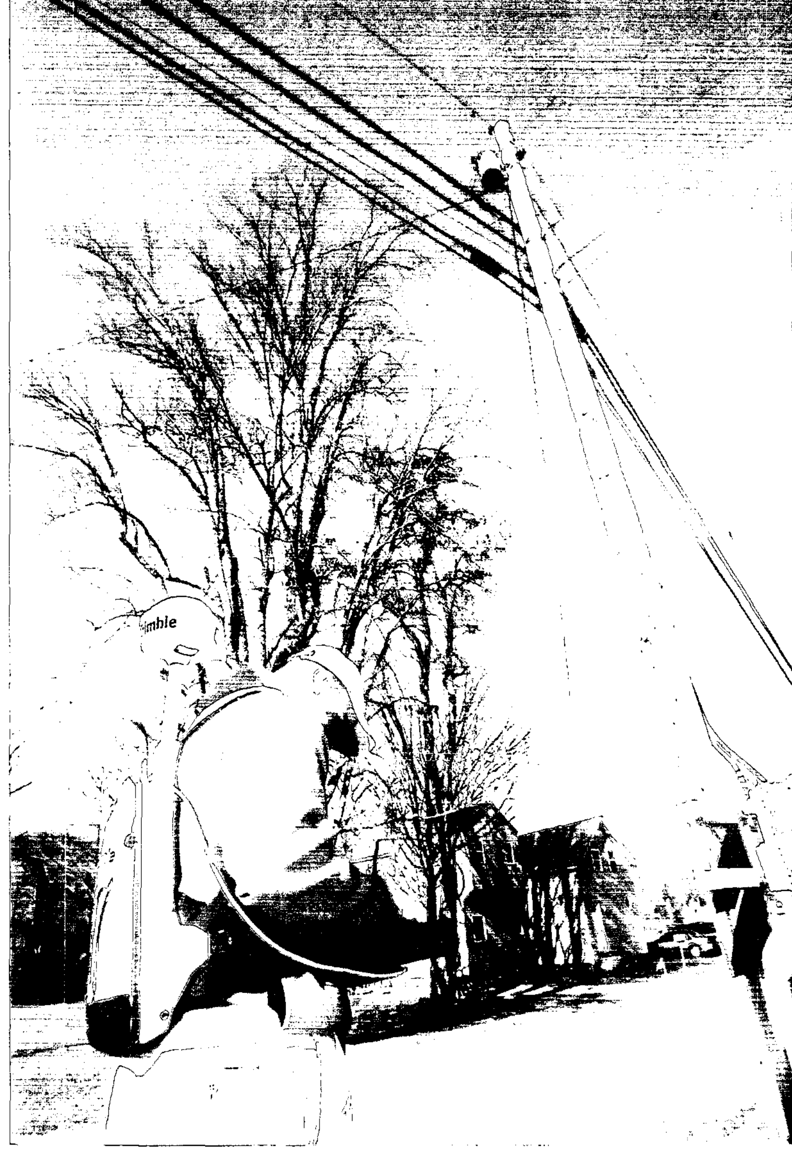
Currently, when Vermont Yankee is offline for planned or unplanned outages, CVPS and other owners are forced to go into the market to buy power, while still paying the costs to run the plant. Once Entergy assumes ownership, CVPS will pay nothing to Vermont Yankee if the plant isn't running. The deal also offloads the risk for any increase in decommissioning costs to Entergy.

The sale is subject to approval of the Public Service Board and several other state and federal agencies. In January of 2002, the Department of Public Service filed testimony with the PSB, outlining conditions for approval of the sale. Specifically, regulators want to ensure that Vermont has the opportunity to purchase power from Vermont Yankee should the plant be relicensed in 2012, and are seeking financial assurances that Entergy will be able to meet its decommissioning obligations whenever the plant is closed. PSB hearings began in February, with a decision expected by July.

Independent Power Deal Cuts Costs

Ending years of often-bitter litigation, CVPS, 13 other Vermont utilities and the state's independent power producers filed a settlement that would save Vermont consumers between $11 million and $45 million.

The settlement would initially reduce power costs for the 14 companies by $11 million to $14 million over 10 years. The parties also agreed to seek a change



Southeastern Reprographics Inc. employee Heath Larson enters location coordinates and other data about CVPS's distribution system into his computer in Wallingford. The data collected will ultimately enable the company to analyze and fix problems much more quickly.

in law to allow the buy-down or buyout of the IPPs' power contracts, which could save another $20 million to $30 million. A bill to that effect is pending in the Vermont General Assembly.

Improve Customer Service

Technology Provides Service Improvements

Even as we took the difficult steps necessary to restore financial stability, CVPS continued to find ways to improve customer service.

The past year brought us an early spring snowstorm that employees described as the worst in 30 years. It dropped more than 22 inches of heavy, wet snow, and a summer tornado-like microburst touched down in Rutland, scattering trees and poles like matchsticks.

Given Vermont's weather, rugged terrain and the rural nature of the land that bears our 8,300 miles of line, power outages are inevitable. Despite that, CVPS's record of reliability ranks with the best anywhere, and in 2001 the company made significant progress on an initiative to further improve our ability to assess and address storm damage.

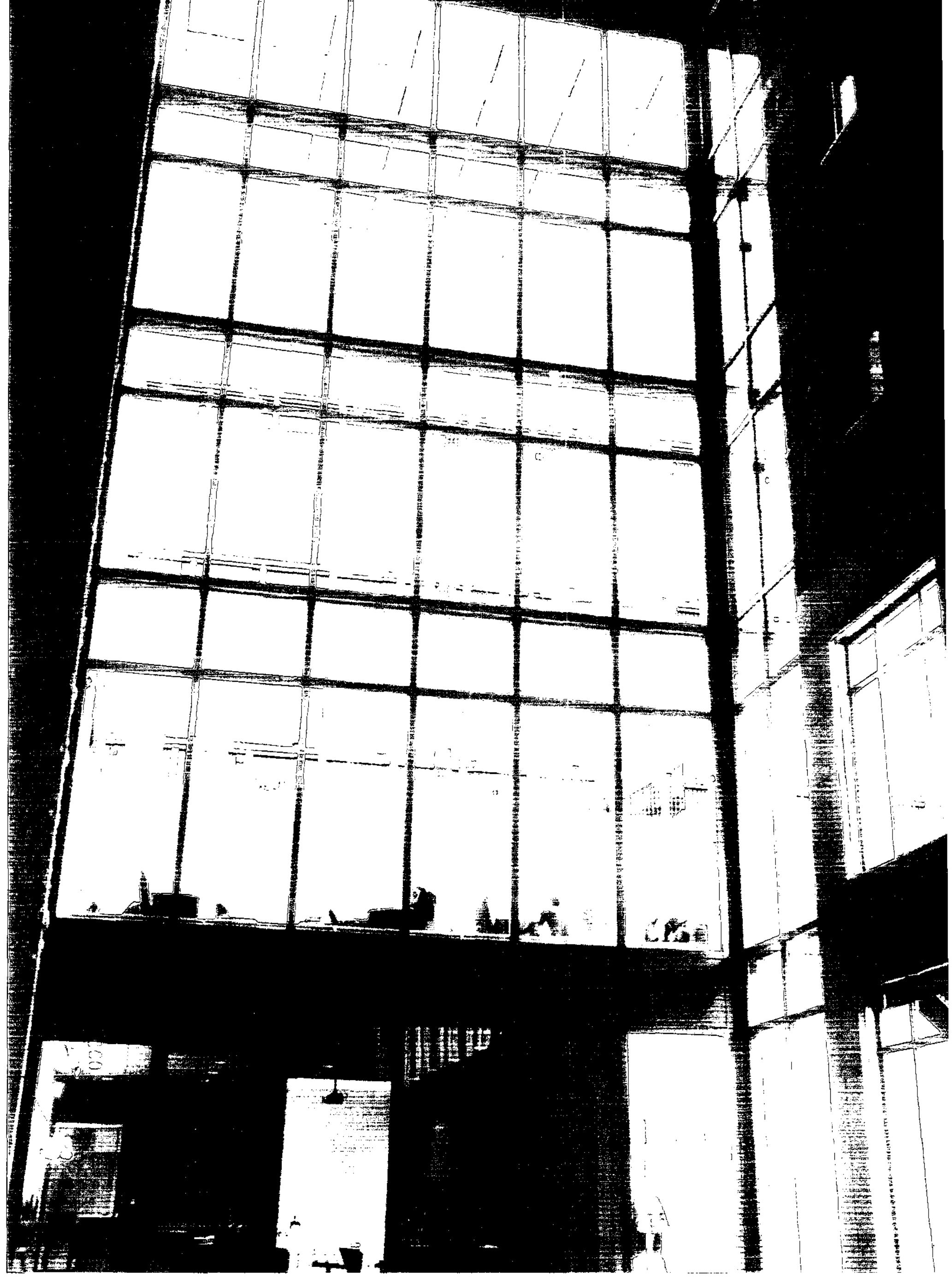
Working with Southeastern Reprographics Inc., we began an inventory of every pole in the 146 cities and towns we serve in Vermont and New Hampshire. With Global Positioning System antennas attached to their backs and laptop computers strapped to their chests, SRI employees are pinpointing the exact location of every pole, wire, transformer and switch. The physical coordinates, a digital photograph and other information are entered into the computer for laser transfer into CVPS's database.

When complete, this database will greatly reduce the time it takes to determine the extent of storm damage to our system, whether it is a statewide event or a localized problem. We will know every customer affected, even if they don't call. That will significantly improve response times and our strategy for attacking the outages.

CVPS Offers Service Guarantees to Customers

In December, the Public Service Board adopted a performance yardstick designed by CVPS and the Department of Public Service to further improve the services our customers count on most. This yardstick will measure CVPS's work against 17 agreed-upon standards. Collectively referred to as SERVE — Serving Everyone with Reliability, Value and Excellence — compliance with the standards may be used one day to determine our rates.

For the next two years, the SERVE standards will measure everything from answering customer calls to installing new services, from outage frequency and duration to worker safety. For example, the customer call center's goal is to answer 70 percent of calls within 20 seconds. SERVE also includes an annual, independent survey to assess customer satisfaction with reliability, service restoration and billing. A successor set of performance standards will be adopted at the end of this two-year term, and may contain financial incentives and penalties related to performance.



Above: Bruce MacDonald (left), executive vice president of Vermont Pure Springs, and Dave Winslow, CVPS senior energy consultant, survey the output of a new production line for the bottled water company, to ensure its load is served in the most-efficient manner possible.

Right: "Knowledge once gained casts a light beyond its own immediate boundaries." Middlebury College's new science center, Bicentennial Hall, seemingly embodies this John Tyndall quote. CVPS and the college work together to meet the college's electrical demands.

CVPS OFFERS CUSTOMERS $10 CREDIT GUARANTEES

CVPS's ongoing commitment to improving service quality and reliability has taken another step forward, with new customer guarantees.

Included are three service promises, backed by customer credits if the company does not deliver as expected.

CVPS guarantees bill accuracy, on-time crew appointments, and a delivery window for scheduled meter work. If the company fails to deliver as promised, the affected customer will be credited $10 on their next bill.

Perhaps most important to customers, CVPS now offers three service guarantees. The company guarantees bill accuracy, line crew appointments for scheduled customer jobs within a two-hour window, and meter work scheduling. If we fail to fulfill any of these commitments, the customer will receive a $10 credit — guaranteed.

CVPS will report SERVE results quarterly to show how we "measure up" against this yardstick. The first report, which covered the quarter ended Dec. 31, 2001, was quite positive. The company surpassed, in some cases by significant margins, most of the standards. The call center, for instance, answered 82.2 percent of calls within 20 seconds, far surpassing the 70 percent standard.

CVPS will use SERVE to further improve our high-quality service and enhance our accountability to customers. This focus is especially critical as we prepare for the likely transition from cost-based rates to rates based on performance, and is central to our efforts to provide new shareholder value.

Build Shareholder Value

Finding "The Right Way to Work"

Providing unsurpassed customer service and creating shareholder value, the twin goals of any public company, became more closely connected than ever in 2001. Along with SERVE, CVPS began to systematically work smarter for our customers while building value for our shareholders in a process we call the Right Way to Work.

While CVPS has significantly reduced costs and streamlined the company over the past 10 years, we believe the improvement process is never ending. Our goal is to eliminate the difference between the way we do our work now, and the way it would be done if everything were "perfect." Aligning every employee's work toward this ideal state is transforming CVPS from a good company to a great one.

To ensure success in purging excess costs, every employee was trained in the Right Way to Work. This system for the improvement of work is built on the ideas of Dr. W. Edward Deming, who helped transform Japan's major industries into world leaders. Bill Conway of Conway Management Inc. worked closely with Deming, then built a comprehensive framework of work-improvement strategies based on measurement, and is working with CVPS employees to methodically identify, quantify and eliminate waste through continuous process improvement.

The cornerstone of his system is the belief that if waste is eliminated, only value-added work remains. Employees focus on customers' needs, and use simple measurement techniques to eliminate waste, which serves customers and shareholders alike.

For example, employees have begun to catalog how, when and why company vehicles are used, how long they idle, and how much fuel is consumed. In so doing, they hope to improve the efficiency of our fleet, and ultimately cut fuel costs.

As we go to print, dozens of other Right Way to Work projects are underway in a concentrated assault on costs at all levels of the company. Whether reading meters or managing power supply risk, street light repair or disaster recovery, every service we provide and every job we do will be brought under systematic scrutiny.

Key to this new effort, we've adopted a handful of critical goals, known as the Vital Few. These goals are the focal point of management's vision, and every employee's work priorities are aligned with them. We consider the Vital Few essential to successfully serving both shareholders and customers and taking CVPS to a new level of service and value creation.

They are: to refrain from seeking rate increases for as long as possible by using Right Way to Work savings to offset cost pressures; to reduce transmission and generation costs and risk; to fully engage employees through the Right Way to Work; to surpass CVPS's new service quality standards; and to create new shareholder value.

(Left to Right) Van Purcell, John te Riele, Chris Gandin, Ann Briere, Joyce Roberts, Bill Martin, Jaye Auer and Karl Hummel discuss ways to reduce repair time for street and security light problems. This Right Way to Work project expects to produce work processes that better utilize line crew time, reduce repair time and increase customer satisfaction.

ELECTRIPAY SIMPLIFIES CUSTOMER PAYMENTS

For additional customer convenience, CVPS initiated Electripay, an electronic payment service offered free to our Vermont and New Hampshire customers.

No more checks. No more stamps. Customers fill out a simple enrollment form to have their bill payments automatically deducted from their checking or savings account each month.

In just four months, nearly 5,000 customers have signed up for this timesaving opportunity which also reduces CVPS's bill-processing costs.

Catamount Energy Embraces Winds of Change

Wind energy's time has come. Wind is a clean, renewable and secure energy source, and the latest technology is increasingly competitive. Catamount Energy, CVPS's wholly owned subsidiary, believes wind will have the lowest production costs of any renewable energy source, making it ideal to fill niche power needs.

With an eye toward creating new value, Catamount Energy sharpened its strategic direction in 2001, focusing on the development, ownership and operation of wind projects. This new focus necessitated a repositioning of Catamount's non-wind asset portfolio and an evaluation of assets that ultimately prompted the write-down of some of the existing assets. However, taking those necessary actions positions Catamount for more solid and rapid growth in 2002 and the years ahead. Catamount will now invest primarily in wind energy projects, including greenfield development and operating projects, in the United States and Western Europe.

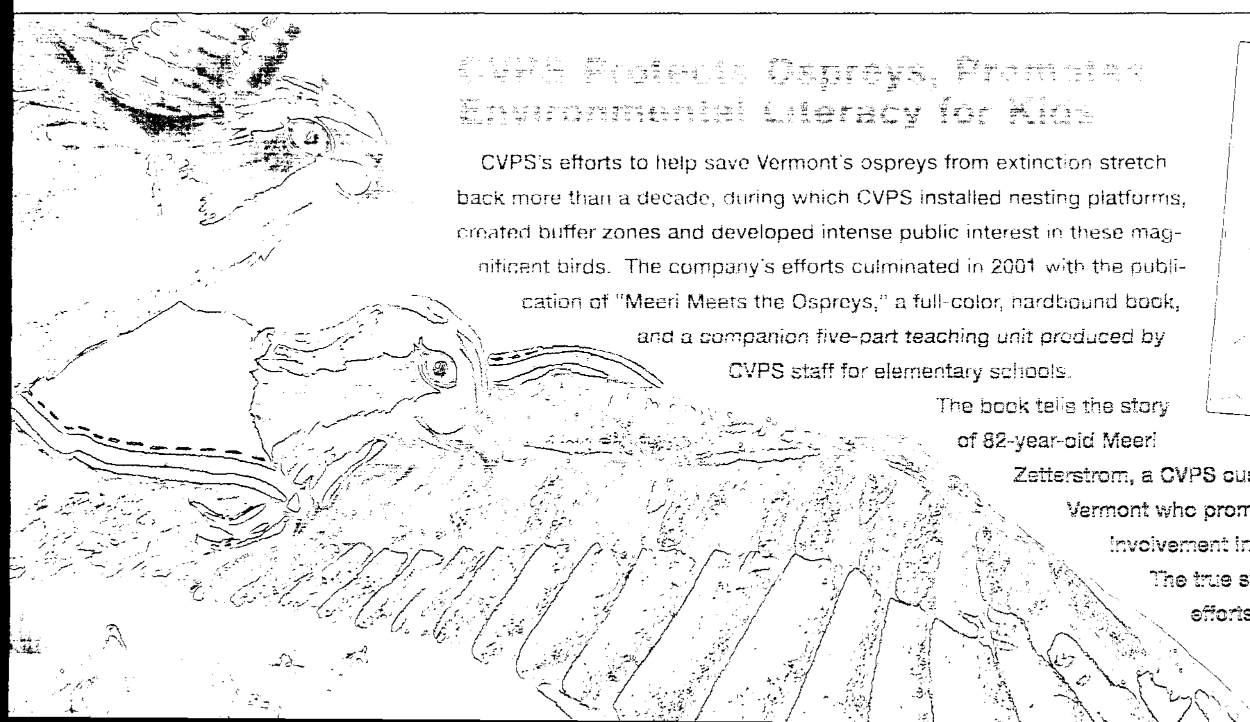
In 2001, Catamount built on its existing expertise through the addition of executive decision-makers with records of success in building high-growth, independent power businesses. Asset performance improved in 2001, and the company began to evaluate existing non-wind assets for potential sales that would free up capital for new wind projects.

This excellent opportunity in the wind sector is a good fit with CVPS's capabilities. We are playing to our strengths, building a management team with a proven track record in the area we are investing, and concentrating on a niche market that matches our financial resources. Catamount's goal of rapid growth and disciplined investing will create long-term value for CVPS.

The Home Service Store Builds on Record of Growth

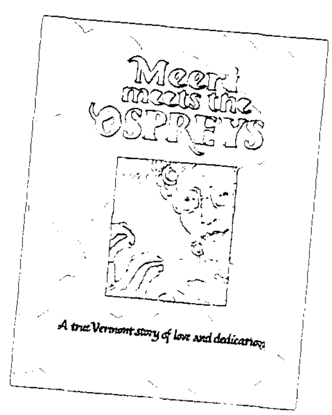
CVPS affiliate The Home Service Store continued its solid record of growth in 2001, with a 134 percent increase in revenues from 2000. HSS, a nationwide membership organization that offers one-stop solutions for home improvement, maintenance and repairs, achieved this remarkable growth in part by entering new marketing partnerships with AAA and Home Depot, deals that complement its existing relationships with True Value and Sam's Club.

Michael Fronin assumed the president and chief executive officer's position in February 2002, after an extremely successful tenure in various executive positions at Circuit City. He replaced Doug Sinclair, whose skill and vision, both at CVPS and HSS, is largely responsible for this affiliate's rapid expansion. Fronin is recognized nationally as an effective leader and operator of growing businesses, and his experience and background are expected to prove invaluable as HSS continues its national growth. □



CVPS Protects Ospreys, Promotes Environmental Literacy for Kids

CVPS's efforts to help save Vermont's ospreys from extinction stretch back more than a decade, during which CVPS installed nesting platforms, created buffer zones and developed intense public interest in these magnificent birds. The company's efforts culminated in 2001 with the publication of "Meeri Meets the Ospreys," a full-color, hardbound book, and a companion five-part teaching unit produced by CVPS staff for elementary schools.



The book tells the story of 82-year-old Meeri Zetterstrom, a CVPS customer in northern Vermont who prompted the company's involvement in osprey protection. The true story chronicles efforts by Zetterstrom,

The Kavelstorf Windfarm, located in Mecklenburg-Vorpommern, Germany, consists of four 1.3-megawatt wind turbines and two 1-megawatt wind turbines. The windfarm began operation in April 2001 and is ultimately expected to generate approximately 13 gigawatt–hours, enough electricity to power over 4,000 homes with a clean and reliable source of energy.

Wind energy's time has come. Wind is a clean, renewable and secure energy source, and the latest technology is increasingly competitive.

EDISON ELECTRIC INSTITUTE

CVPS NAMED FINALIST FOR 2001 EDISON AWARD

CVPS was named one of four finalists for the 2001 Edison Award, the Edison Electric Institute's highest honor. It is presented to one American utility and one international affiliate each year "for distinguished leadership, innovation and contribution to the advancement of the electric industry."

CVPS, the smallest utility ever named a finalist, was so honored based on our innovative strategy to partner with larger companies to build new businesses and customer services. As EEI stated in announcing the nominations, "CVPS exemplifies the results of creative, aggressive business ventures – in this case transforming a small local utility into a global player."

the company and the Vermont Department of Fish & Wildlife to help the birds successfully hatch a chick, the first at Lake Arrowhead in more than two decades.

The company gave a free copy of the book to every third-grade student, elementary school and public library in the state. Additional copies were sold, with proceeds donated to the Department of Fish & Wildlife's Non-Game and Natural Heritage Program, with which CVPS partnered to protect ospreys.

The learning unit helps teachers bring the story of Meeri, CVPS and the ospreys to life through interactive activities that help youngsters understand the interconnection between plants, animals, birds, fish and humans.

Nearly 100 schools have incorporated the learning unit into their science and environmental studies. Hundreds of school children have written to the company to ask questions about the ospreys, Meeri and our work to save the birds. Hundreds more students, parents, teachers, principals and librarians from across the state have written letters of thanks.

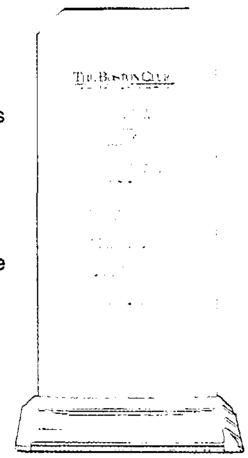
Governor Howard Dean, left, and CVPS's Bob Young applaud as a smiling Meeri Zetterstrom accepts an original drawing that appears in the CVPS-published book, "Meeri Meets the Ospreys". The presentation, on Meeri's front meadow overlooking Lake Arrowhead, followed the governor's reading of the book to a group of Georgia Elementary School third-graders in sight of a newly constructed osprey platform.

CVPS Board Leadership Award

For the second time, CVPS received The Boston Club Award in 2001 for the company's continued commitment to women.

The Boston Club, a national organization of professional and executive women, honored CVPS for being one of the few companies in New England with three or more women on their boards of directors.

The CVPS Board of Directors includes Mary Alice McKenzie, Janice Scites and Rhonda Brooks, and advisory director Janice Case, who will be up for election at the 2002 annual meeting.



Frederic H. Bertrand
(65)/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
(61)/1996/Executive Vice President and President, Commercial, Government and Industrial Solutions Sector, Motorola Inc., Schaumburg, Illinois (Communications Equipment) (2)(4)

William V. Boettcher
(54)/2001/Chief Executive Officer, Fletcher Allen Health Care, Burlington, Vermont (3)

Rhonda L. Brooks
(49)/1996/President, Exterior Systems Business, Owens Corning, Toledo, Ohio (Building Materials and Fiberglass Composites) (3)

Robert G. Clarke
(51)/1997/Chancellor of the Vermont State Colleges, Waterbury, Vermont (2)

Timothy S. Cobb
(60)/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
(68)/1979/President, Hackett, Valine & MacDonald Inc., Burlington, Vermont (Insurance) (1)(2)

George MacKenzie Jr.
(52)/2001/Executive Vice President and Chief Financial Officer, Glatfelter Company, York, Pennsylvania (Global Manufacturer of Specialty Papers and Engineered Products) (2)

Mary Alice McKenzie
(44)/1992/Vice President and General Counsel, Vermont State Colleges, Waterbury, Vermont (3)(4)

Janice L. Scites
(51)/1998/President, Scites Associates Inc., Basking Ridge, New Jersey (Technology and Business Consulting Firm) (3)

Herbert H. Tate
(48)/2001/Research Professor of Energy Policy Studies, New Jersey Institute of Technology, Newark, New Jersey (2)

Robert H. Young
(54)/1995/President and Chief Executive Officer, Central Vermont Public Service (1)(4)

Janice B. Case, ***Non-Voting Advisory Director***
(49) Former Senior Vice President, Energy Solutions, Florida Power Corporation, St. Petersburg, Florida (Electric Utility)

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

Robert H. Young
(54)/1987/President and Chief Executive Officer

Kent R. Brown
(56)/1996/Senior Vice President, Engineering and Operations

Joseph M. Kraus
(46)/1981/Senior Vice President, Customer Service, Secretary and General Counsel

James J. Moore Jr.
(43)/2001/Senior Vice President, and President and Chief Executive Officer Catamount Energy Corporation

Craig A. Parenzan
(45)/2001/Senior Vice President, Business Development

William J. Deehan
(49)/1985/Vice President, Transmission and Generation Planning and Regulatory Affairs

Robert E. Rogan
(42)/1998/Vice President, Public Affairs

Joan F. Gamble
(44)/1989/Vice President, Strategic Change and Business Services

John J. Holtman
(45)/2000/Vice President and Controller

Mary C. Marzec
(52)/1989/Assistant Corporate Secretary

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 the actions of regulators, the outcome of litigation at the Federal Energy Regulatory Commission ("FERC") involving the Company's regulated companies, the performance of the Vermont Yankee nuclear power plant ("Vermont Yankee"), weather conditions, the performance of the Company's unregulated businesses and the state of the economy in the areas served. The Company cannot predict the outcome of any of these matters.

CRITICAL ACCOUNTING POLICIES

Preparation of the Company's financial statements in accordance with generally accepted accounting principles 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. Note 1 to the Consolidated Financial Statements is a summary of the significant accounting policies used in the 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, the New Hampshire Public Utilities Commission and the 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 No. 71, "Accounting for the Effects of Certain Types of Regulation", or SFAS No. 71, for both its regulated service territories and FERC-regulated wholesale businesses. 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 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 an amount that could be material. 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 are 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 market value of the long-lived asset.

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 property, plant or equipment, they are considered executory in nature.

Other Other significant accounting policies include: 1) estimated unbilled revenues recorded at the end of each quarterly accounting period; 2) depreciation based on the straight-line remaining life method; and 3) income taxes recorded in accordance with SFAS No. 109, "Accounting for Income Taxes."

EARNINGS OVERVIEW

Central Vermont Public Service Corporation's (the "Company") 2001 net income was $2.4 million, or $.06 per basic and diluted share of common stock, which equates to a 0.4% consolidated return on average common equity. This compares to net income and earnings per basic and diluted share of common stock of $18.0 million and $1.42 in 2000, and $16.6 million and $1.28 in 1999. The consolidated return on average common equity was 8.6% for 2000 and 7.9% for 1999.

Excluding all nonrecurring items discussed below, the Company's net income for 2001 was $16.0 million, or $1.24 per basic and diluted share of common stock. This compares to 2000 net income of $13.7 million, or $1.05 per basic and diluted share of common stock, which excludes nonrecurring income related to the favorable Millstone Unit #3 settlement and the favorable Connecticut Valley Electric Company ("Connecticut Valley") First Circuit Court of Appeals decision.

The Company's rate case settlement with the Vermont Department of Public Service ("DPS") increased rates 3.95% effective July 1, 2001, and put to rest the issues surrounding the Vermont utilities' power contract with Hydro-Quebec. As a result, the Company was required to take a one-time charge to earnings of $5.3 million after-tax, or $.46 per share, and had a $1.7 million after-tax, or $.15 per share, favorable impact due to the elimination of under-recovery of costs related to the Hydro-Quebec power contract.

During 2001, the Company's unregulated subsidiary, Catamount Energy Corporation ("Catamount"), recorded fourth quarter after-tax asset impairment charges of $9.8 million, or $.85 per share, related to four of its investments in non-regulated energy generation projects. The impairment charges are the result of writing down two assets held-for-sale to estimated sales value and issues concerning the future viability of two other operating projects. The Company also had a third quarter extraordinary charge of $0.2 million related to Connecticut Valley, which is again subject to cost-based ratemaking. Earnings in 2000 included nonrecurring income related to the favorable Millstone Unit #3 settlement and Connecticut Valley First Circuit Court of Appeals decision, which are described below.

Other factors affecting 2001 earnings compared to 2000 included: 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% 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; and 5) lower net losses at Eversant Corporation ("Eversant," formerly SmartEnergy Services, Inc.) of $0.2 million after-tax, or $.02 per share, related to Eversant's investment in Home Service Store, Inc. ("HSS"), offset by higher business development costs and a fourth quarter 2001 accrual for a potential income tax liability.

Increased 2000 earnings versus 1999 resulted mainly from nonrecurring income related to the favorable Millstone Unit #3 settlement and the favorable Connecticut Valley First Circuit Court of Appeals decision amounting to $3.2 million after-tax, or $.28 per share, and $1.7 million after-tax, or $.14 per share, respectively, and higher utility revenues of $0.8 million after-tax, or $.06 per share, principally due to a FERC-ordered refund of transmission costs from Citizens Utilities. In addition, Connecticut Valley reversals of disallowed power costs previously accrued and expensed in 1999, had a positive impact of $0.6 million after-tax, or $.05 per share, and lower net losses at Eversant had a positive impact of $0.5 million after-tax, or $.05 per share. Lower operating costs of $1.6 million after-tax, or $.13 per share, resulted from lower service restoration costs and lower regulatory costs related to retail rates. This was offset by the negative impact of $2.6 million after-tax, or $.23 per share, due to higher accruals in 2000 for the expected under-recovery of power costs on the Hydro-Quebec power contract compared to 1999, higher net power costs of $2.4 million after-tax, or $.22 per share, primarily resulting from accrued installed capability ("ICAP") deficiency charges, and increased Hydro-Quebec capacity costs. In addition, lower earnings at Catamount amounted to $1.2 million after-tax, or $.12 per share, mainly related to a write-down of a portion of the Gauley River equity investment, higher net losses from Catamount's investment in Thetford and Catamount's share of costs incurred in connection with its investment in a wind farm project in Germany.

RESULTS OF OPERATIONS

The major elements of the Consolidated Statement of Income are discussed below.

Operating revenues and megawatt-hour ("mWh") sales A summary for 2001, 2000, and 1999 follows:

	mWh Sales			Revenues (000's)		
	2001	2000	1999	2001	2000	1999
Residential	952,509	963,615	948,756	$124,844	$124,237	$123,302
Commercial	933,928	933,851	943,141	110,482	106,089	109,440
Industrial	431,371	465,418	442,308	35,888	38,521	36,823
Other retail	6,291	6,280	6,235	1,787	1,779	1,787
Total retail sales	2,324,099	2,369,164	2,340,440	273,001	270,626	271,352
Resale sales:						
Firm	1,927	2,830	2,349	139	142	160
Entitlement (1)	165,184	299,326	195,149	7,303	10,763	10,840
Alliance	-	611,225	2,986,682	-	22,192	100,116
Other	406,694	573,055	869,857	16,153	20,534	22,121
Total resale sales	573,805	1,486,436	4,054,037	23,595	53,631	133,237
Other revenues	-	-	-	5,880	9,669	5,191
Total	2,897,904	3,855,600	6,394,477	$302,476	$333,926	$409,780

(1) Effective January 1, 2000, power purchased from Hydro-Quebec was recorded net of Entitlement sales to Hydro-Quebec, therefore, the 1999 Entitlement sales have been restated for comparison purposes in the table above.

Year-to-year fluctuations in total retail mWh sales are affected by economic conditions, weather patterns, and customer usage patterns, which are affected by the absolute cost of electricity and its costs relative to other fuel sources. Retail mWh sales for 2001 decreased 45,065 mWh, or 1.9%, while related revenues increased $2.4 million for 2001 compared to 2000. The June 26, 2001 approved rate order, which allowed for a 3.95% increase in retail rates beginning in July 1, 2001, contributed approximately $4.9 million and the favorable impact of customer mix and unit pricing contributed $1.7 million, while the 1.9% decrease in mWh sales resulted in a $4.2 million decrease. The decline in retail sales in 2001 can be attributed to both mild weather patterns and the slowing economy's impact on many of the Company's industrial customers.

Compared to 1999, retail mWh sales for 2000 increased 28,724 mWh, or 1.2%, and related revenues decreased $0.7 million, or 0.3%. The revenue decrease was primarily attributable to the rate reduction for the funding of the State of Vermont-sponsored Energy Efficiency Utility ("EEU").

For 2001, Entitlement mWh sales decreased 45% when compared to 2000, due in part to the discontinuance, in October 2001, of a five-year power contract in which the Company sold approximately 15% of its share of Vermont Yankee output at full cost. Additionally, in 2000 and 2001, the Company entered into short-term unit swap transactions where it sold a small portion of its share of Vermont Yankee for an equal share of the output from other nuclear facilities in New England; the offsetting purchases are included in the Purchased Power and Produced Energy (mWh) table below. In 2001, the Vermont Yankee swap transactions of approximately $1.1 million were included in Other, while the swap transactions of approximately $2.2 million in 2000 were included in Entitlement, in the table above.

For 2000, Entitlement mWh sales increased 53% when compared to 1999. The increase primarily resulted from Vermont Yankee short-term unit swap transactions as described above. In addition, 1999 included a Vermont Yankee refueling outage, while there was no refueling outage in 2000.

Other resale sales decreased 166,361 mWh, or 29%, in 2001 compared to 2000, primarily due to lower output and purchases from the Company's power resources, which impacts 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 the decrease in Other were Vermont Yankee unit swap transactions, which were included in Other in 2001 and Entitlement in 2000.

Other resale sales in 2000 decreased 296,802 mWh compared to 1999 and related revenues decreased $1.6 million. These variances reflected current market conditions in Vermont and New England. These sales made on a short-term basis included sales to ISO-New England and other utilities in New England.

Alliance resale sales in 2000 and 1999 resulted from activity by the Company through its Alliance with Virginia Power in jointly supplying wholesale power primarily in the Northeast states. In the third quarter of 1999, the Company and Virginia Power agreed to discontinue the Alliance. For 2000, Alliance resale sales decreased 2,375,457 mWh and related revenues decreased $77.9 million compared to 1999. Alliance-related sales ended in December 2000.

The $3.8 million decrease in Other revenues in 2001 compared to 2000 primarily resulted from 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.

Compared to 1999, Other revenues in 2000 increased $4.5 million partly due to the items explained above.

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

	2001	2000
Revenue increase (decrease) from:		
Retail mWh sales	$ (4,239)	$ 2,880
Retail rates (unit price)	6,614	(3,606)
Changes in firm resale sales	(3)	(18)
Changes in entitlement sales	(3,460)	(77)
Change in Alliance sales	(22,192)	(77,924)
Changes in other resale sales	(4,381)	(1,587)
Changes in other revenues	(3,789)	4,478
Net decrease over prior year	$(31,450)	$(75,854)

Purchased power The Company purchases approximately 90% of its power needs under several contracts of varying duration. Over 30% of its purchases are from affiliated companies whereby the Company receives its entitlement share of the output. The Company's purchased power portfolio assures that a diversified mix of sources and fuel types are available to meet the Company's long-term load growth while providing short- and intermediate-term opportunities to purchase or sell capacity and energy to reduce overall power costs. A breakdown of the Company's energy sources, including the unit swap transactions and excluding sources related to the Alliance, is shown below:

Sources of Energy	2001	2000	1999
Nuclear generating companies	43%	43%	34%
Canadian imports	35	34	35
Company-owned hydro	4	6	5
Jointly owned units	6	8	6
Independent power producers	6	6	5
Other sources	6	3	15
	100%	100%	100%

The Company maintains a 1.7303% joint-ownership interest in Unit #3 of the Millstone Nuclear Power Station and owns a 2% equity interest in Connecticut Yankee. Unit #3 is currently operated by Dominion Nuclear Connecticut ("DNC"), a subsidiary of Dominion Resources, Inc., and Connecticut Yankee is operated by Northeast Utilities ("NU"). The Company maintains joint-ownership interests in Joseph C. McNeil, a 53 mW wood, gas and oil-fired unit, and Wyman #4, a 619 mW oil-fired unit, and also owns a 2% and 3.5% equity interest in Maine Yankee and Yankee Atomic, respectively. The Company owns a 31.3% equity interest in Vermont Yankee, of which its ownership percentage changed to 33.23% in the first quarter of 2002 related to the buy-back of shares held by minority owners of the plant, which is explained in more detail below. The Company's entitlement percentage of Vermont Yankee is 35%. In addition, the Company owns 20 hydroelectric generating units with a total nameplate capability of 44.7 mW and two gas-fired and one diesel-peaking unit with a combined nameplate capability of 28.9 mW.

During scheduled nuclear refueling outages, the Company purchases more costly replacement energy from other sources to satisfy energy needs. In accordance with current ratemaking treatment, the Company defers and amortizes to expense, over their respective fuel cycles, the incremental replacement energy and maintenance costs associated with refueling outages for Vermont Yankee and Millstone Unit #3. During 2001, the Company deferred $5.4 million for maintenance costs.

Millstone Unit #3

On July 27, 2000, the Company and the other non-operating owners of Unit #3 reached a settlement with NU related to a demand for arbitration filed in 1997 for recovery of costs resulting from the shutdown of Unit #3 in 1996. In August 2000, as a result of the settlement, the Company received a cash settlement of $5.4 million.

On September 15, 1999, NU announced its intent to auction its nuclear generating plants, including Unit #3. On August 7, 2000, the Connecticut Department of Public Utility Control announced that Dominion Resources, Inc. was the successful bidder in the auction. Pursuant to the terms of the August 2000 settlement described above, the Company participated as a potential seller in that auction, however, upon notification of the sales price, the Company declined the purchase offer. The sale to DNC became final on March 31, 2001. Unit #3 continues to be a jointly owned plant, and the Company is one of two minority owners. The total DNC share of Unit #3 is 93.4707%.

As part of the regulatory approvals of the sales to DNC by the joint owners of that plant, DNC has represented to the Nuclear Regulatory Commission ("NRC") and other regulatory bodies, including the Connecticut Department of Public Utility Control, that the Millstone Unit #3 Decommissioning Trust Fund, for its share of the plant, exceeds the NRC minimum calculation required and therefore no further contributions to the fund are required at this time. The Company has agreed with the DPS position in its recent rate case that the DNC representation that contributions currently can cease is appropriate subject to periodic review of both the fund balance and the NRC minimum calculation upon which the DNC bases its assertion of fund adequacy. The Company could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded.

Vermont Yankee

The Vermont Yankee nuclear power plant, which provides more than one-third of the Company's power supply, began a scheduled refueling outage on April 27, 2001, which ended on May 20, 2001, 11 days shorter than budgeted. The previous refueling outage began on October 29, 1999 and the plant returned to service December 2, 1999. The 1998 refueling outage (March 21-June 3) extended 26 days beyond the scheduled 49 days. The next scheduled refueling outage is October 2002.

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

On October 15, 1999, the Company and the other owners of Vermont Yankee accepted a bid for sale of the plant to AmerGen Energy Company ("AmerGen") and on November 17, 1999, Vermont Yankee executed an Asset Purchase Agreement with AmerGen. On November 16, 2000, the owners of Vermont Yankee accepted and submitted to the PSB an improved offer for the sale of the plant to AmerGen.

On February 14, 2001, the PSB issued its Order Dismissing Petition in Docket No. 6300, the proceeding in which the Company, along with GMP, Vermont Yankee and AmerGen sought PSB approval of the sale of the Vermont Yankee nuclear plant to AmerGen. In this Order, the PSB determined that the proposed purchase price, as filed in November 2000, pursuant to a Memorandum of Understanding, did not reflect the fair market value of the plant and, therefore, the sale did not promote the general good of the State of Vermont. This ruling was consistent with the Company's position. The PSB dismissed the petition for approval in March 2001. The management of Vermont Yankee subsequently concluded that selling the plant at auction would provide the greatest benefit to the owners and consumers. The investment banking firm of JPMorgan was retained by Vermont Yankee as the exclusive financial advisor for the auction.

As a result of issues raised related to the cancelled AmerGen sale, Vermont Yankee reached an agreement in principle with the Vermont Yankee sponsors and their secondary power purchasers, the DPS and the FERC staff that reduces the Vermont Yankee cost of service the sponsors and the secondary purchasers will expect to pay through 2012. The agreement is reflected in billings to sponsors and secondary purchasers effective July 2001. The FERC approved the agreement on September 13, 2001.

On August 15, 2001, Vermont Yankee announced that a sales agreement had been reached with Entergy Corporation ("Entergy") for $180 million, representing $145 million for the plant and related assets and $35 million for nuclear fuel. Entergy will also assume decommissioning liability for the plant and its decommissioning trust fund. The agreement includes a purchase power contract with prices that generally range from 3.9 cents to 4.5 cents per kilowatt-hour subject to a "low-market adjuster" that protects the current Vermont Yankee owner-utilities, including the Company and its power consumers, in the event power market prices drop significantly. On September 27, 2001, the Company filed testimony with the PSB in support of the sale. In an order entered October 26, 2001, the PSB granted intervention to several parties that the Company did not oppose, and established a schedule that provides for discovery, hearings and final briefing by April 29, 2002. Certain of the intervenors were secondary purchasers of Vermont Yankee power, which were seeking adjustments in their power purchase contracts, and stockholders of Vermont Yankee, which were asserting dissenters' rights. On January 16, 2002, Vermont Yankee announced that it had reached an agreement with the secondary purchasers and had purchased back the shares held by the minority stockholders; these parties have requested to withdraw from the PSB proceeding.

On January 7, 2002, the DPS and the remaining intervenors prefiled their direct testimony in the PSB proceeding. Initial hearings occurred during the first week of February 2002 with prefiled rebuttal testimony due on February 25, 2002, and rebuttal hearings March 18 through March 22, 2002. The current schedule in the PSB proceeding could permit a closing, if the sale is approved, by the end of July 2002. The Company cannot predict the outcome of the proceedings.

The sale is also subject to other regulatory approvals including the Nuclear Regulatory Commission and the Securities and Exchange Commission.

Maine Yankee

On August 6, 1997, the Maine Yankee nuclear power plant was prematurely retired from commercial operation. The Company relied on Maine Yankee for less than 5% of its required system capacity. The decommissioning effort continues per project plans. The total expected decommissioning costs for Maine Yankee are $536.0 million in 1998 dollars. The original decommissioning contractor, Stone and Webster, filed for bankruptcy and, in January 2002, Maine Yankee and Federal Insurance agreed on a settlement of the pending litigation arising from contract performance when Stone and Webster went into bankruptcy. A settlement payment of $44.0 million has been deposited into the Maine Yankee Decommissioning Trust Fund. Future payments for the closing, decommissioning and recovery of the remaining investment in Maine Yankee, including the insurance settlement, are currently estimated to be approximately $494.2 million; the Company's share is expected to be approximately $9.9 million to be paid over the period 2002 through 2008.

On January 19, 1999, Maine Yankee and the active intervenors filed an Offer of Settlement with the FERC, which the FERC has approved. As a result, all issues raised in the FERC proceeding, including recovery of anticipated future payments for closing, decommissioning and recovery of the remaining investment in Maine Yankee, are resolved. Also resolved are the issues raised by the secondary purchasers, who purchased Maine Yankee power through agreements with the original owners, limiting the amounts they will pay for decommissioning the Maine Yankee plant and settling other points of contention affecting individual secondary purchasers.

Connecticut Yankee

On December 4, 1996, the Connecticut Yankee nuclear power plant was prematurely retired from commercial operation. The Company relied on Connecticut Yankee for less than 3% of its required system capacity. Connecticut Yankee continues to decommission the site. Connecticut Yankee reached a settlement with the FERC and the intervenors that allows for the cost recovery of the total expected decommissioning costs now estimated at $569.0 million in January 2000 dollars, as well as other appropriate costs of service. The settlement rates became effective September 1, 2000, following the FERC order of July 26, 2000. Connecticut Yankee is required to commence a new filing before the FERC no later than July 1, 2004 to review the status of decommissioning expenditures, the expected remaining decommissioning costs and their collections, and other appropriate issues. Future payments for the closing, decommissioning and recovery of the remaining investment in Connecticut Yankee are currently estimated to be approximately $226.6 million; the Company's share is expected to be approximately $4.5 million to be paid over the period 2002 through 2007.

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% of its system capacity. As of July 2000, Yankee Atomic had collected from its sponsors sufficient funds, based on a current forecast, to complete the decommissioning effort and to recover all other FERC-approved costs of service. Therefore, Yankee Atomic discontinued billings to its sponsors pending the need to increase or decrease the funds available for the completion of its financial obligations, including decommissioning. Such a change would require a FERC review and approval. Yankee Atomic is successfully decommissioning the site as planned.

Maine Yankee, Connecticut Yankee and Yankee Atomic Decommissioning Costs

Currently, costs billed to the Company by Maine Yankee and Connecticut Yankee, including a provision for ultimate decommissioning of the units, are being collected from the Company's customers through existing retail and wholesale rate tariffs. As of December 31, 2000, the Company completed its obligation for decommissioning costs based on current estimates related to Yankee Atomic. The Company's share of remaining costs with respect to Maine Yankee and Connecticut Yankee's decisions to discontinue operation were estimated to be $10.6 million and $4.5 million, respectively, at December 31, 2001. These amounts are subject to ongoing review and revisions and are reflected in the accompanying Consolidated Balance Sheet both as regulatory assets and nuclear dismantling liabilities (current and non-current). In the first quarter of 2002, the Company plans to revise its estimates related to Maine Yankee to reflect the impact of the insurance settlement described above.

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. This 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, Connecticut Yankee and Yankee Atomic decommissioning costs will be recovered through the regulatory process and, 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.

Cogeneration/Independent Power Qualifying Facilities

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. Under these long-term contracts, in 2001, the Company received 168,382 mWh of which 118,187 mWh is associated with the Vermont Electric Power Producers and 37,293 mWh from a waste-to-energy electric generating facility owned by Wheelabrator Claremont Company, L.P. The Company expects to purchase approximately 197,000 mWh of independent power output in each year 2002 through 2006. Based on the forecast level of production, the total commitment in the next five years to purchase power from these independent power facilities is estimated to be $116 million, which excludes the impact of the January 28, 2002 Memorandum of Understanding described below.

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 purchase 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, the other moving utilities and the DPS requested that the PSB issue an order requiring GMP's full participation in the PSB proceeding. The PSB declined to rule on the request but retained authority to require GMP to provide specific information or to submit any other specific filing.

On November 22, 2000, the IPPs filed dispositive motions in Docket No. 6270, urging the PSB to declare that it lacks jurisdiction to grant relief sought by the Company's Petition. On January 8, 2001, the Company and the other petitioning utilities filed responses to the IPPs' motions, supporting the PSB's exercise of jurisdiction, as called under the Petition. The DPS also made a filing in support of jurisdiction. On June 1, 2001, the PSB Hearing Officer issued a Proposal for Decision ("PFD") on the PSB's jurisdiction to consider the Petition. The PFD recommended that the PSB find that it has jurisdiction to consider the relief sought under the Petition but that the PSB may be precluded from issuing orders reducing the lengths of a Purchasing Agent contract or requiring buy-outs or buy-downs. Docket participants filed comments on the PFD. On September 18, 2001, the PSB issued an Order regarding jurisdiction in which it adopted the conclusions of the Hearing Officer's PFD and found that it has jurisdiction to consider five of the seven claims outlined in the original Petition.

The IPPs also filed a related proceeding in the Washington County Superior Court contending that the PSB rules pertaining to IPPs, which the utilities have relied upon, in part, in their Petition before the PSB, contains a so-called "scrivener's error." By motion filed in the Superior Court in September 2000, the IPPs sought summary judgement in this action. On January 19, 2001, the Washington County Superior Court dismissed the IPPs' action, which the IPPs appealed to the Vermont Supreme Court. The IPPs also asked the Vermont Supreme Court to stay the proceeding before the PSB pending the outcome of their appeal. By order dated April 5, 2001, the Vermont Supreme Court denied the IPPs' request for a stay.

On March 15, 2001, the IPPs also filed a related complaint before the FERC, requesting that the FERC issue an order preventing the Company and the other Vermont utilities from employing FERC Order No. 888 to require the IPPs, either directly or indirectly, to reserve transmission service and pay transmission charges in connection with their power sales. In principal part the IPPs argue that such reservations and related charges are prohibited under the regulations adopted by the State of Vermont to implement the Public Utilities Regulatory Policies Act of 1978. On April 4, 2001, the Company and other Vermont utilities filed their response arguing that the IPP complaint should be dismissed on procedural grounds and opposing the IPPs' allegations on the merits. By Order dated May 16, 2001, the Commission declined to grant the relief requested and instead found that the complaint was premature in light of the fact that the PSB has yet to rule on the disputed issues in the proceeding open before it to consider the Petition.

In September 2001, the Petitioners and the IPPs agreed to enter into a settlement discussion and on September 28, 2001 filed a Stipulation for Stay requesting that further proceedings in the Docket be stayed to provide the parties an opportunity to engage in settlement negotiations. A similar motion was also filed with the Vermont Supreme Court regarding the appeal on the so-called "scrivener's error" case. On October 18, 2001, the PSB Hearing Officer issued an order granting the Stipulation for Stay and indicated that a status conference would be convened midway through the 90-day period, which was due to expire January 4, 2002. A status conference on the parties' settlement efforts was convened on November 27, 2001.

After several extensions, on January 28, 2002, the Petitioners and the IPPs filed a Memorandum of Understanding with the PSB which, if approved, establishes a comprehensive settlement to the issues in Docket No. 6270. The Memorandum of Understanding would provide:

1) power cost reductions nominally worth approximately $11.0 million to $14.0 million over ten years;
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.

At this time, proceedings are continuing in PSB Docket No. 6270 to consider the Memorandum of Understanding. A status conference on the matter was held in February 2002. A decision in this matter is expected in 2002.

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 eight separate hydroelectric projects under the Federal Power Act. These projects, some of which are grouped together under a single license, represent approximately 29.9 mW, or about 66.8% 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 6.2 mW hydroelectric station on the Lamoille River. The Vermont Natural Resources Council ("VNRC") has proposed removal of the dam, a 1948 hydro-generating unit that produces power to energize approximately 3,000 homes per year.

In August 2000, talks broke down, and the VNRC called publicly for removal of the dam. The Company has initiated broader discussions with VNRC, Trout Unlimited, the Vermont Agency of Natural Resources and other parties, related to the economic, reliability and environmental issues that Peterson's removal would create.

Other

In order to optimize its power mix for baseload, intermediate and peaking power, the Company engages in purchases and sales with other electric utilities primarily in New England and with the ISO-New England hourly clearing market to take advantage of immediate pricing and other market conditions. Revenue from sale transactions is used to reduce purchased power costs. Purchases from ISO-New England are included in Other sources in the Sources of Energy table above. The Company also engaged in marketing activities with Virginia Power, which jointly supplied wholesale power primarily in the Northeast states, however, in the third quarter of 1999, the Company and Virginia Power agreed to discontinue the Alliance and the remaining committed purchases under the Alliance were fulfilled in 2000. These purchases are excluded from the Sources of Energy table above.

Net Purchased Power and Production Fuel

The net cost components of purchased power and production fuel costs, including Alliance purchases, for the past three years were as follows (dollars in thousands):

	2001		2000		1999 (1)	
	Units	Amount	Units	Amount	Units	Amount
Purchased and produced:						
Capacity (mW)	436	$ 86,164	427	$ 96,850	545	$ 90,879
Energy (mWh)	2,784,443	61,498	3,594,942	89,090	6,208,364	168,546
Total purchased power costs		147,662		185,940		259,425
Production fuel (mWh)	320,022	2,995	452,387	4,825	402,355	3,165
Total purchased power and production fuel costs		150,657		190,765		262,590
Less entitlement and other resale sales (mWh)	571,878	23,456	1,483,607	53,489	4,051,688	133,077
Net purchased power and production fuel costs		$127,201		$137,276		$129,513

(1) Effective January 1, 2000, power purchased from Hydro-Quebec was recorded net of entitlement sales to Hydro-Quebec, therefore, the 1999 Purchased and produced energy and entitlement and other resale sales have been restated for comparison purposes in the table above.

For 2001, purchased capacity costs decreased $10.7 million compared to 2000 primarily related to the following: 1) favorable impact of $5.0 million related to a second quarter 2001 reversal of a $2.5 million power cost accrual in 2000 related to estimated ICAP deficiency charges to ISO-New England due to a December 2000 FERC Order, which was reversed in 2001; 2) the June 26, 2001 rate order that eliminated future disallowances for the under-recovery of Hydro-Quebec power costs, resulting in a $2.9 million favorable impact from the reversal of the accrual for estimated under-recovery of Hydro-Quebec power costs in the second quarter of 2001, with no accrual for the future under-recovery of those costs in the third quarter of 2001; and 3) lower Vermont Yankee capacity costs of $3.8 million (including the $5.5 million impact of a net deferral of refueling outage costs) related to lower decommissioning costs beginning July 1, 2001, lower net interest costs and operational efficiencies at the plant.

Energy costs are directly related to the variable prices of oil and nuclear fuel, but more importantly, to the proportion of the Company's purchased energy that comes from each of these fuel sources. Purchased energy in 2001 decreased $27.6 million compared to 2000, primarily due to Alliance-related purchases of approximately $22.0 million in 2000, which are offset by a decrease in Alliance resale sales. Excluding Alliance-related energy purchases, purchased energy for 2001 decreased $7.6 million compared to 2000 due to a decrease in 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.

In 2001, 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.

For 2000, purchased capacity costs increased $6.0 million compared to 1999, resulting from the negative impact of higher loss accruals of $4.6 million in 2000 for expected under-recovery of power costs on the Hydro-Quebec power contract and accrued ICAP deficiency charges in ISO-New England of $2.5 million due to a December 2000 FERC Order, which was on appeal. In addition, costs related to the Hydro-Quebec power contract increased by $5.4 million. The increased capacity costs were partially offset by a favorable impact of lower Connecticut Valley loss accruals related to disallowed power costs of $1.2 million, lower Vermont Yankee capacity costs of $2.3 million including the impact of refueling outage deferrals, lower decommissioning costs of $1.0 million, which was primarily related to Yankee Atomic, and lower Alliance-related capacity costs of $1.6 million.

Energy purchases decreased by $79.4 million for 2000 compared to 1999, primarily from a $76.7 million decrease in Alliance purchases, which are offset by a decrease in Alliance resale sales. Excluding the Alliance, energy purchased decreased by $2.7 million for 2000, primarily from a 4.0%, or $5.3 million, decrease in the amount of mWh purchased offset by a 7.5%, or $2.6 million, increase in price.

In 2000, production fuel costs increased $1.7 million compared to 1999 primarily due to increased operation of the McNeil generating plant to support reliability due to an equipment failure in northern Vermont, and increased fuel costs.

The Company is responsible for paying its entitlement percentage of decommissioning costs for Vermont Yankee, Connecticut Yankee, Maine Yankee and Yankee Atomic, as well as its joint-ownership percentage of decommissioning costs for Millstone Unit #3. For additional information see Notes 2 and 13 to the Consolidated Financial Statements. The staff of the Securities and Exchange Commission has questioned certain current accounting practices of the electric utility industry, including the Company, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in financial statements of electric utilities. In response to these questions, the Financial Accounting Standards Board ("FASB") issued a new accounting pronouncement related to asset retirement obligations that includes decommissioning of nuclear power plants. See discussion of Recent Accounting Pronouncements below.

Based on present commitments and contracts, the Company expects that net purchased power and production fuel costs will be approximately $142.1 million, $139.2 million and $140.7 million for the period 2002 through 2004.

Other operation expenses There was no significant variance related to other operation expenses for 2001 compared to 2000. The decrease of approximately $3.2 million for 2000 versus 1999 resulted primarily from decreased regulatory commission costs related to retail rates as well as decreased conservation and load management costs in 2000, primarily as a result of the EEU.

Maintenance expenses The $3.4 million increase in maintenance expense in 2001 compared to 2000 is primarily due to higher service restoration costs related to storm activity in the first quarter of 2001. The decrease in maintenance expenses of $2.8 million in 2000 versus 1999 is primarily due to lower service restoration costs related to two major storms that occurred in 1999.

Income taxes Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences. Income taxes increased in 2001 compared to 2000 due to changes in permanent differences and an increase in the valuation allowance. For 2000 versus 1999 these taxes decreased as a result of a change in permanent differences for the period.

Other income and deductions Other income and deductions decreased $24.0 million for 2001 compared to 2000 due mainly to the following nonrecurring items: 1) a $9.0 million pre-tax write-off related to the Company's June 2001 approved rate order; 2) $8.9 million of pre-tax asset impairment charges related to Catamount's investments; and 3) a $1.9 million pre-tax write-down of Eversant's investment in HSS. See Diversification below for more detail. Other income and deductions increased for 2000 versus 1999 due to the positive impact of nonrecurring income of $5.4 million related to the favorable Millstone Unit #3 settlement, offset by an increase in the provision for income taxes. The decrease in 1999 was primarily due to lower equity income from Eversant's proportionate share in HSS.

Interest on long-term debt There was no significant variance in interest on long-term debt in 2001 compared to 2000. In July 1999, the Company sold $75.0 million aggregate principal amount of 8 1/8% Second Mortgage Bonds due 2004. Accordingly, interest on long-term debt increased for 1999 and 2000. Interest expense reflects the retirement of first mortgage bonds of $4.0 million in 2001, $16.5 million in 2000 and $3.0 million in 1999.

Other interest expense The $0.6 million increase in Other interest expense in 2001 compared to 2000 resulted primarily from a fourth quarter 2001 accrual for interest due on a potential tax liability. Other interest expense decreased for 2000 versus 1999 due to decreases in average outstanding short-term debt.

Extraordinary Charge An Extraordinary charge of $0.2 million resulted from the application of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS No. 71"), at Connecticut Valley.

LIQUIDITY AND CAPITAL RESOURCES

The Company's liquidity is primarily affected by the level of cash generated from operations and the funding requirements of its ongoing construction programs. The Company's capital expenditure projections for the years 2002 through 2006 total approximately $90.3 million; these projections are revised from time-to-time to reflect changes in conditions. Net cash flow provided by operating activities generated $30.2 million of cash in 2001, $60.9 million of cash in 2000 and $31.2 million in 1999. The $30.7 million decrease in cash from operating activities for 2001 versus 2000 can be attributed to: 1) the scheduled nuclear refueling outages at Vermont Yankee and Millstone Unit #3 in 2001 with no scheduled refueling outages in 2000; 2) the Millstone Unit #3 settlement in 2000; and 3) other changes in working capital.

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. The decrease in cash for 2001 was the result of $30.2 million provided by operating activities, offset by $30.6 million used for investing activities and $2.1 million used for financing activities.

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.

Utility

On July 30, 1999, the Company sold $75.0 million aggregate principal amount of 8 1/8% Second Mortgage Bonds due 2004 at a price of 99.915%.

Based on outstanding debt at December 31, 2001, the aggregate amount of utility long-term debt maturities and sinking fund requirements are $7.0 million, $10.5 million, $75.0 million, $0.0 million and $0.0 million for the years 2002 through 2006, respectively. Substantially all 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 that support three series of Industry Development/Pollution Control Bonds, with expiration dates of May 31, 2002. The Company has begun the process of extending these letters of credit to August 31, 2003 with Citizens Bank of Massachusetts. 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, 2001, the Company was in compliance with all debt covenants related to its various debt agreements.

Financial obligations of the Company's subsidiaries, discussed below, are non-recourse to the Company. On April 25, 2001, the Company sought and, in June 2001, the Company received unanimous approval from its First Mortgage Bondholders to enter into a 42nd Supplemental Indenture to the Company's mortgage dated October 1, 1929 (the "First Mortgage") to exclude its wholly owned non-regulated subsidiary, Catamount Resources Corporation and its subsidiaries (currently Catamount and Eversant), from the term "subsidiary" under the Mortgage. The 42nd Supplemental Indenture (amendment) eliminates the possibility of cross defaults under the First Mortgage occasioned by a default on the indebtedness of Catamount Resources Corporation or its subsidiaries. Additionally, the amendment imposes limitations on the level of the Company's future investment in non-regulated subsidiaries.

Non-Utility

In 1998, Catamount replaced its $8.0 million credit facility with a $25.0 million revolving credit/term loan facility, maturing November 2006, which provides for up to $25.0 million in revolving credit loans and letters of credit, of which $21.3 million was outstanding at December 31, 2001. 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, 2001, the aggregate amount of Catamount's long-term debt maturities are $0.0 million, $3.2 million, $4.2 million, $5.0 million and $9.1 million for the years 2002 through 2006, respectively. Catamount's long-term debt contains financial and non-financial covenants. At December 31, 2001, Catamount was in compliance with all covenants under the revolver except that Catamount's capital expenditures exceeded budget by an immaterial amount, which was waived by the lender in February 2002.

In 1999, SmartEnergy Water Heating Services, Inc. ("SEWHS"), a wholly owned subsidiary of Eversant, secured a $1.5 million, seven-year term loan with Bank of New Hampshire with an outstanding balance of $1.1 million at December 31, 2001. The interest rate is fixed at 9.5% per annum. Based on outstanding debt at December 31, 2001, the aggregate amount of SEWHS's long-term debt maturities are $0.2 million, $0.2 million, $0.2 million, $0.3 million and $0.2 million for the years 2002 through 2006, respectively. SEWHS's long-term debt contains financial and non-financial covenants. At December 31, 2001, SEWHS was in compliance with all debt covenants related to its various debt agreements.

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	2001	2000	1999
Common stock equity	47%	49%	47%
Preferred stock	6	6	6
Long-term debt	43	41	43
Capital lease obligations	4	4	4
	100%	100%	100%

Credit Ratings

Current credit ratings of the Company's securities by Standard & Poor's and Fitch IBCA ("Fitch") remain 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

On July 11, 2001, Fitch removed the Company from its "Rating Watch Negative" status because of its favorable resolution of the Company's rate order with the PSB.

On July 17, 2001, Standard & Poor's removed the Company from its "CreditWatch with negative implications" status in response to the PSB's recent rate order, which stabilized the Company's financial position. Standard & Poor's also affirmed its rating of the Company, saying that its outlook on the Company is stable.

The Company cannot assure that its business will generate sufficient cash flow from operations or that future borrowing will be available to the Company in an amount sufficient to enable the Company to pay its indebtedness, including the $75.0 million Second Mortgage Bonds, when due or to fund its other liquidity needs. The Company's ability to repay its indebtedness is, to a certain extent, subject to general economic, financial, competitive, legislative, regulatory, weather and other factors that are beyond its control. The type, timing and terms of future financing that the Company may need will be dependent upon its cash needs, the availability of refinancing sources and the prevailing conditions in the financial markets. The Company cannot guarantee that financing sources will be available to the Company at any given time or that the terms of such sources will be favorable.

DIVERSIFICATION

Catamount Resources Corporation was formed for the purpose of holding the Company's subsidiaries that invest in non-regulated business opportunities. Catamount, a subsidiary of Catamount Resources Corporation, invests through its wholly owned subsidiaries in non-regulated energy-supply generation projects in North America and Western Europe. Through its wholly owned subsidiaries, Catamount has interests in ten operating independent power projects located in Glenns Ferry and Rupert, Idaho; Rumford, Maine; East Ryegate, Vermont; Thetford, England; Hopewell, Virginia; Thuringen, Germany; Mecklenburg-Vorpommern, Germany; Fort Dunlop, England; and Summersville, West Virginia.

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. As a result of the change in strategic direction, Catamount is currently pursuing the sale of certain of its interests in non-wind electric generating assets. Depending on prices, capital and other requirements, Catamount will also entertain offers for the purchase of any of its remaining non-wind electric generating assets. Proceeds from the 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 November 1999, Catamount partnered with Tyco Capital (formerly CIT Group), a major equipment finance company, and Dana Commercial Credit Corporation ("Dana"), the finance subsidiary of Dana Corporation, to form Catamount Investment Company, LLC ("CIC"), which intended to invest in independent power projects in North America. CIC Luxembourg SarL ("CIC Luxembourg") was also established by the parties mentioned above to invest in independent power projects in Western Europe. CIC Luxembourg participated in two German projects. Tyco Capital, Dana and Catamount decided to dissolve CIC effective December 31, 2001. Catamount recorded a nominal charge to earnings associated with the dissolution of CIC.

Catamount has projects under development in the United States and Western Europe. In June 2001, Catamount established Catamount Development GmbH, a German corporate entity, 100% owned by Catamount Heartlands Corp., a wholly owned subsidiary of Catamount. The company was formed to hold Catamount's interests in German "greenfield" development by Catamount or projects, which would be purchased by Catamount in mid- to late-stage development.

Summersville Hydroelectric Power Station, owned by Gauley River Power Partners, L.P. ("Gauley River"), which was still under construction in the first half of 2001, began commercial operation on July 30, 2001. The project experienced construction delays and Gauley River incurred a $0.6 million liquidated liability to its primary purchased power contract holder during July 2001, as a result of power production delays. In November 2001, Catamount and Gauley River signed an agreement to settle the construction dispute related to the cost overruns with the contractor, Black & Veatch Construction, Inc. ("Black & Veatch"), which was approved by the lenders. Under the terms of the agreement, Catamount and Gauley River have agreed to pay Black & Veatch a total of $6.8 million. This amount represents $5.0 million as final settlement on the construction overruns and $1.8 million related to the release of retainage upon completion of certain construction items outlined in the agreement. Of the $6.8 million, $5.8 million was paid in the fourth quarter 2001 and the remaining $1.0 million will be paid in the first quarter 2002.

At December 31, 2001, Gauley River was classified as held-for-sale and the project interests are being actively marketed for sale by Catamount. In the fourth quarter, in accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" ("SFAS No. 121"), Catamount recorded an after-tax impairment charge to earnings of $1.4 million associated with its interests in Gauley River. The impairment was based on bids received from third parties, less estimated costs to sell. In late December 2001, Catamount issued requests for bids to several parties interested in Gauley River and, in February 2002, entered into an exclusive agreement for the sale of the project.

Although Catamount has a controlling interest in Gauley River, this investment has not been consolidated in the accompanying financial statements since it is Management's intent to sell this project and therefore control is considered temporary. For equity accounting purposes, the Gauley River investment is treated as 100% ownership.

Catamount's Fibrothetford Limited ("Fibrothetford") equity investment has been reduced to zero as a result of losses incurred to date. As of July 1, 2001, losses were being applied to Catamount's note receivable balance. Catamount will also reserve against future interest income on the note receivable, which is expected to be approximately $1.3 million over the next twelve months. Fibrothetford received a deferment of the senior debt principal payment due September 30, 2001, avoiding a potential default. That deferred payment was made at the end of

October 2001. Fibrothetford is negotiating a refinancing of its debt with a large commercial bank and its owners; Management, however, cannot predict whether Fibrothetford will ultimately be able to restructure its debt and continue as a going concern. At year end, Catamount's Fibrothetford investment was classified as held-for-sale. In the fourth quarter, in accordance with SFAS No. 121, Catamount recorded an after-tax impairment charge to earnings of $3.2 million. Also, a valuation allowance for the $2.2 million deferred tax asset was recorded. The impairment charge was based on review of expected future cash flows and expected market value of Catamount's interest given the project's current financial condition.

In the fourth quarter 2001, Catamount recorded impairment charges for all of its interests in the Glenns Ferry and Rupert projects for a total after-tax charge of $3.0 million. 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. The steam hosts are actively seeking resolution of their current financial issues, however, Management cannot predict whether they will ultimately be successful.

Catamount's after-tax loss for 2001 was $8.7 million and its after-tax earnings were $0.7 million and $2.1 million for 2000 and 1999, respectively.

Eversant, also a subsidiary of Catamount Resources Corporation, invests in unregulated energy and service-related businesses. Eversant had a 13.4% ownership interest, on a fully diluted basis, in HSS as of December 31, 2001. HSS establishes a network of affiliate contractors who perform home maintenance repair and improvements via membership. HSS began operations in 1999 and is subject to risks and challenges similar to a company in the early stage of development. HSS launched a Commercial Services division in 2001, which meets the needs of small businesses, building owners and property managers. In May 2001, Eversant entered into a convertible loan agreement with HSS and Jupiter Capital ("Jupiter"). Under the agreement, Eversant loaned HSS $2.0 million and Jupiter loaned HSS $5.0 million, which, along with current debt balances and accrued interest, was converted to preferred securities when HSS received an additional cash investment from Jupiter in August 2001. In September 2001, Eversant recorded a $1.2 million after-tax write-down of its investment in HSS to fair market value. Eversant has previously recorded losses of $9.0 million related to its investment in HSS. At year end, Jupiter committed, based upon continued satisfactory operating progress, to provide an additional $5.0 million in funding to the business over time. The first $1.0 million was invested in December 2001 and Jupiter received options to acquire up to an aggregate of $4.0 million in preferred securities. In January 2002, Jupiter invested an additional $1.0 million and predicts that an additional $2.0-$3.0 million in funding above the $5.0 million may be required and they are currently talking to other parties about providing this capital. Eversant's fully diluted ownership position after the $5.0 million Jupiter investment would be 12.6%.

In February 2002, HSS announced that Michael Froning, formerly President of the Southern Division of Circuit City Stores, will become President and Chief Executive Officer.

Eversant's share of the HSS losses for 2001 was zero as the Company's equity investment was reduced to zero as a result of losses incurred to date. As of December 31, 2001, Eversant has a preferred equity investment in HSS of $1.4 million, recorded at estimated fair value.

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 markets and sells 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. The Company does not expect a material liability related to the decision and is currently in discussions with Westfalia-Surge regarding this matter. The SmartDrive Control product has generated approximately 75% of the sales revenue of AgEnergy. AgEnergy's revenues represent approximately $0.4 million of the total Eversant revenues of approximately $2.4 million, on an annual basis.

Overall, Eversant incurred net losses of $2.1 million, $2.3 million and $2.9 million for 2001, 2000 and 1999, respectively.

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.

Vermont Retail Rate Proceedings

1997 Retail Rate Case: The Company filed for a 6.6%, or $15.4 million per annum, general rate increase on September 22, 1997 to become effective June 6, 1998 to offset increasing costs of providing service. Approximately $14.3 million, or 92.9%, 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 Company's September 1997 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 made a filing 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." During February 1998, the DPS filed testimony in opposition to the Company's retail rate increase request. The DPS recommended that the PSB instead reduce the Company's then current retail rates by 2.5%, or $5.7 million. 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.

1998 Retail Rate Case: On June 12, 1998, the Company filed with the PSB for a 10.7% retail rate increase that supplanted the September 22, 1997 rate increase request of 6.6%, to be effective March 1, 1999. On October 27, 1998, the Company reached an agreement with the DPS regarding the June 1998 retail rate increase request providing for a temporary rate increase in the Company's retail rates of 4.7%, or $10.9 million on an annualized basis, beginning with service rendered on or after January 1, 1999. The agreement was approved by the PSB on December 11, 1998.

The 4.7% 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. The agreement temporarily disallowed approximately $7.4 million (based on 1999 power costs) for the Company's purchased power costs under the VJO Power Contract. As a result of the 4.7% rate increase agreement, during the fourth quarters of 1998 and 1999, the Company recorded pre-tax losses of $7.4 million and $2.9 million, respectively, for disallowed purchased power costs, representing the Company's estimated under-recovery of power costs, prior to further resolution, under the VJO Power Contract for 1999 and the first quarter of 2000, respectively. In 2000, an additional $11.5 million pre-tax loss was recorded for the estimated under-recovery of Hydro-Quebec power costs for the second, third and fourth quarters of 2000, and the first quarter of 2001. In the first quarter of 2001, an additional $2.9 million pre-tax loss was recorded for the estimated under-recovery of Hydro-Quebec power costs for the second quarter of 2001. 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 based on the favorable outcome of the Company's June 26, 2001 rate order, which is described below.

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% rate increase ($19.0 million of annualized revenues) effective July 24, 2001. The PSB suspended the rate filing and a schedule was set to review the case.

On February 9, 2001, the Vermont Supreme Court issued a decision on the Company's 1998 rate case appeal that reversed the PSB's decision on the preclusion issues and remanded the case to the PSB for further proceedings consistent with the Vermont Supreme Court's decision.

The Company's June 26, 2001 rate order, which is described below, 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.

On May 7, 2001, the Company and the DPS reached a rate case settlement that would end uncertainty over the future recovery of Hydro-Quebec contract costs, allow a 3.95% rate increase, make the January 1, 1999 temporary rates permanent, permit a return on equity of 11% for the twelve months ending June 30, 2002 for the Vermont utility, and create new service quality standards. The Company also agreed to a second quarter $9.0 million one-time write-off ($5.3 million after-tax) of regulatory assets and a rate freeze through January 1, 2003.

On June 26, 2001, the PSB issued an order on the Company's rate case settlement with the DPS. In addition to the provisions outlined above, the approved rate order requires the Company to return up to $16.0 million to ratepayers in the event of a merger, acquisition or asset sale if such sale requires PSB approval. As a result of the rate order, the 3.95% rate increase became effective with bills rendered July 1, 2001, and in June 2001 the Company recorded a $5.3 million after-tax loss to write off certain regulatory assets as agreed to in the settlement. The Company was able to accept the 3.95% rate increase versus the 7.6% increase it requested since 1) regulatory asset amortizations will decrease approximately $3.5 million, on a twelve-month basis, due to the $9.0 million one-time write-off of regulatory assets and 2) Vermont Yankee decommissioning costs decreased approximately $1.9 million, on a twelve-month basis, after the rate case was filed as a result of an agreement between Vermont Yankee and the secondary purchasers.

Deseasonalized Rates: On June 8, 2000, the PSB approved the Company's request to end the winter-summer rate differential and, therefore, the Company now has flat rates throughout a given year. Winter rates were reduced by 14.9%, while summer rates were increased by 10.5%. The rate design change was revenue neutral over a twelve-month period. The additional revenues in 2000, resulting from implementing this change in mid-year, 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'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.

In the third quarter of 2001, Management determined that Connecticut Valley is again subject to cost-based ratemaking and qualifies for the application of SFAS No. 71. This decision was based on the favorable Court of Appeals decision of July 25, 2000 and the subsequent denial of the NHPUC's petition for writ of certiorari by the United States Supreme Court on February 20, 2001, as well as other regulatory developments in New Hampshire during 2001. The application of SFAS No. 71 resulted in an extraordinary charge of $0.2 million for Connecticut Valley.

See Note 12 to the Consolidated Financial Statements for further discussion.

PROPOSED FORMATION OF HOLDING COMPANY

In order to further prepare the Company for deregulation, and to insulate the Company from the risks of its various regulated and unregulated subsidiaries, the Company filed a petition with the PSB in 1998 for permission to create a holding company that would have as subsidiaries the Company and non-utility subsidiaries, Catamount and Eversant and their subsidiaries. The proposal had been revised to have Connecticut Valley become a direct subsidiary of the holding company, rather than remain as a subsidiary of the Company. The Company believed that a holding company structure would reduce the Company's Vermont utility's cost of capital and thus would be beneficial to its ratepayers, and would also benefit any future transition to a deregulated electricity market in Vermont. The proposed holding company formation was subject to approval by Federal regulators, including the Securities and Exchange Commission, the FERC, various States and the Company's shareholders. The Company had negotiated an agreement with the DPS regarding code of conduct and affiliate transaction rules to be utilized once a holding company structure is implemented.

As part of the settlement in the June 26, 2001 rate order, the Company and the DPS agreed to develop and file a schedule for the consideration of the holding company structure for the Company, and to submit an agreement supporting the approval of affiliate transaction rules and codes of conduct for a new holding company. The PSB approved the schedule for the holding company docket, which schedule anticipated a settlement filing, if any, in September 2001 and set forth a schedule for litigation, if necessary, beginning in December 2001. The Company and the DPS were unable to reach a resolution of issues, and the Company filed a motion to dismiss its petition. On September 24, 2001, the PSB issued its Order Closing Docket, without prejudice. The Company cannot predict whether it will request PSB approval of a holding company structure in the future.

ELECTRIC INDUSTRY RESTRUCTURING

The electric utility industry is in a period of transition that may result 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 Vermont and New Hampshire, where the Company does business, are exploring 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. Recent events, including those related to restructuring in California and uncertainties concerning the operations of the wholesale markets in New England, have resulted in a slowdown of the restructuring process in Vermont.

Vermont

Recently, there have been three primary sources of Vermont governmental activity in attempting to restructure the electric industry in Vermont: 1) the Governor's Working Group, created by the Governor of Vermont; 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, the proceeding has been closed and the Company has actively pursued initiatives for such purposes. 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.

NEW HAMPSHIRE - FERC 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 $83.0 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. Absent termination of the wholesale rate schedule by mutual agreement, the earliest termination date that could presently occur pursuant to the wholesale rate schedule is December 31, 2003. The stranded cost obligation as of December 31, 2003, expressed on a net present value basis set forth in the ALJ order, is approximately $33.9 million.

The ALJ's Initial Decision is subject to review and approval by the FERC. If the Company is unable to obtain approval by the FERC, and if Connecticut Valley is forced to terminate its relationship as a wholesale customer of the Company, it is possible that the Company would be required to recognize a pre-tax loss under this contract totaling approximately $32.9 million as of December 31, 2003. The Company would also be required to write off approximately $0.9 million (pre-tax) of regulatory assets associated with its wholesale business as of December 31, 2003. If the Company obtains a FERC order authorizing the updated requested exit fee and notice of termination is given, Connecticut Valley will apply to the NHPUC to increase rates in order to pay the exit fee. The Company believes that the NHPUC must permit Connecticut Valley to raise rates to recover the cost of the exit fee. However, if Connecticut Valley is unable to recover its costs in rates, Connecticut Valley would be required to recognize the loss discussed above.

In addition to its efforts before the Court and FERC, Connecticut Valley has initiated efforts and will continue to work for a negotiated settlement with parties to the New Hampshire restructuring proceeding and the NHPUC.

An adverse resolution of the FERC and New Hampshire proceedings would have a material adverse effect on the Company's results of operations and cash flows. However, the Company cannot predict the ultimate outcome of this matter. See Note 12 to the Consolidated Financial Statements for additional information related to New Hampshire Retail Rates.

Connecticut Valley constitutes approximately 7% of the Company's total retail mWh sales.

REGIONAL TRANSMISSION ORGANIZATIONS (RTO)

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

On May 13, 1999, the FERC issued a notice of proposed rulemaking that would amend FERC's regulations under the Federal Power Act to facilitate the formation of regional transmission organizations ("RTO"). On December 20, 1999, the FERC issued Order No. 2000, which requires all public utilities that own, operate, or control interstate electric transmission to file a proposal for an RTO by October 15, 2000, or in the alternative, a description of any efforts by the utility to participate in an RTO, the reasons for not participating and any obstacles to participation, and any plans for further work toward such participation. The filing date for Order No. 2000 was extended to January 16, 2001 for utilities in regions with an existing independent system operator, such as ISO-New England.

The Company, jointly with GMP, Citizens Utilities and Vermont Electric Power Company, filed its comments on the New England RTO proposal submitted by some of the New England transmission owners and ISO-New England on January 16, 2001.

On July 12, 2001, the FERC issued an order on the New England RTO proposal, which found that the RTO proposed by the New England market participants would be insufficient in its proposed scope and regional configuration to effectively perform an RTO's required functions and to support competitive power markets. The FERC required that the participants in the proceedings involving the three proposed RTOs in the northeast, participate in mediation on forming a single Northeastern RTO. The FERC directed an Administrative Law Judge to mediate settlement discussions with the parties for a period of 45 days and file a report within 10 days (due on September 17, 2001).

From July 24, 2001 through September 7, 2001, the Company participated in joint mediation with approximately 400 other Northeast participants to develop an RTO, which meets the requirements of Order No. 2000. The primary tasks of the mediation were focused on 1) defining the Northeastern RTO's operational paradigm, 2) developing an infrastructure and operating rules, and 3) implementing the RTO across the entire region. As directed by the FERC, the Administrative Law Judge assigned to the mediation filed a report of the mediation on September 17, 2001.

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

COMPETITION - RISK FACTORS

If retail competition is implemented in Vermont or New Hampshire, 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 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 in general. 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.

As described in Note 1 of Notes to Consolidated Financial Statements, the Company believes it currently complies with the provisions of SFAS No. 71 for both its regulated Vermont and New Hampshire service territory and FERC-regulated wholesale businesses.

In the event the Company determines that it no longer meets the criteria for following SFAS No. 71, the accounting impact would be an extraordinary, non-cash charge to operations of approximately $32.4 million on a pre-tax basis as of December 31, 2001. Criteria that 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.

SFAS No. 121, adopted by the Company on January 1, 1996, requires that any assets, including regulatory assets, that are no longer probable of recovery through future revenues, be revalued based upon future cash flows. SFAS No. 121 requires that a rate-regulated enterprise recognize an impairment loss for the amount of costs excluded from recovery. As of December 31, 2001, based upon the regulatory environment within which the Company currently operates, SFAS No. 121 did not have an impact on the Company's regulated businesses. Competitive influences or regulatory developments may impact this status in the future.

Because the Company is unable to predict what form possible future restructuring legislation will take, it cannot predict if or to what extent SFAS No. 71 and 121 will continue to be applicable in the future. See Recent Accounting Pronouncements below for the new accounting standard related to impairment or disposal of long-lived assets, which replaces SFAS No. 121 effective January 1, 2002. If the Company is unable to mitigate or otherwise recover stranded costs that could arise from any potentially adverse legislation or regulation, the Company would have to assess the likelihood and magnitude of losses incurred under its power contract obligations.

As such, the Company cannot predict whether any restructuring legislation enacted in Vermont or New Hampshire, once implemented, would have a material adverse effect on the Company's operations, financial condition or credit ratings. However, the Company's failure to recover a significant portion of its purchased power costs would likely have a material adverse effect on the Company's results of operations, cash flows, ability to obtain capital at competitive rates and ability to exist as a going concern. It is possible that stranded cost exposure before mitigation could exceed the Company's current total common stock equity.

INFLATION

The annual rate of inflation, as measured by the Consumer Price Index, was 2.8% for 2001, 3.4% for 2000 and 2.2% for 1999. 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.

RECENT ACCOUNTING PRONOUNCEMENTS

Derivative Instruments: On January 1, 2001, the Company adopted SFAS No. 133 (subsequently amended by SFAS No. 137 and 138), *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"). This Statement, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

The Company has one long-term purchase 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. On April 11, 2001, the PSB approved an Accounting Order that allows the fair valuation adjustment of this contract to be deferred on the balance sheet as either a deferred asset or liability. At December 31, 2001, this derivative had an estimated fair market value of approximately a $1.0 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.

Goodwill and Other Intangible Assets: In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets* ("SFAS No. 142"), effective for fiscal years beginning after December 15, 2001. SFAS No. 142 establishes a new accounting standard for the treatment of goodwill. The new standard continues to require recognition of goodwill as an asset in a business combination but does not permit amortization as is done under current accounting standards. Effective January 1, 2002, SFAS No. 142 requires that goodwill be separately tested for impairment using a fair-value based approach as opposed to the undiscounted cash flow approach used under current accounting standards. If goodwill is found to be impaired, the Company would be required to record a non-cash charge against income, which would be recorded as a cumulative effect of a change in accounting principle. The impairment charge would be equal to the amount by which the carrying amount of the goodwill exceeds its estimated fair value. The Company has no goodwill related to its regulated businesses, however, Catamount has goodwill of approximately $2.0 million related to three of its investments, but does not expect an impairment resulting from the implementation of SFAS No. 142.

Asset Retirement Obligations: In August 2001, the 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 in the period in which it is incurred. The Company has identified potential retirement obligations associated with the decommissioning of its nuclear facilities, but has not yet completed its assessment. This statement is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. The Company has not yet quantified the impacts, if any, of adopting SFAS No. 143 on its financial statements.

Impairment or Disposal of Long-Lived Assets: In October 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144") which replaces SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.* This statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets. Although SFAS No. 144 supercedes SFAS No. 121, it retains the fundamental provisions of SFAS No. 121 regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under SFAS No. 144, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). SFAS No. 144 is effective beginning January 1, 2002 and, generally, is to be applied prospectively. The Company does not expect that SFAS No. 144 will have a significant impact on its financial position or results of operations.

SELECTED FINANCIAL DATA

(Dollars in thousands, except per share amounts)

	2001	2000	1999	1998	1997
For the year					
Operating revenues	$302,476	$333,926	$419,815	$303,835	$304,732
Net income before extraordinary charge	$ 2,589	$ 18,043	$ 16,584	$ 3,983	$ 17,151
Extraordinary charge, net of taxes	$ 182	-	-	-	$ 811
Net income	$ 2,407	$ 18,043	$ 16,584	$ 3,983	$ 16,340
Earnings available for common stock	$ 711	$ 16,264	$ 14,722	$ 2,038	$ 14,312
Consolidated return on average common stock equity	0.4%	8.6%	7.9%	1.1%	7.5%
Earnings per basic and diluted share of common stock before extraordinary charge	$ .08	$ 1.42	$ 1.28	$ .18	$ 1.32
Earnings per basic and diluted share of Common stock	$ .06	$ 1.42	$ 1.28	$ .18	$ 1.25
Cash dividends paid per share of common stock	$ .88	$ .88	$ .88	$ .88	$ .88
Book value per share of common stock	$ 15.81	$ 16.57	$ 16.05	$ 15.63	$ 16.38
Net cash provided by operating activities	$ 30,216	$ 60,867	$ 31,232	$ 21,743	$ 41,974
Dividends paid	$ 11,433	$ 11,888	$ 11,950	$ 12,006	$ 12,630
Construction and plant expenditures	$ 16,553	$ 14,968	$ 13,231	$ 16,046	$ 13,841
Conservation and load management expenditures	$ 504	$ 1,136	$ 2,440	$ 2,208	$ 1,837
At end of year					
Long-term debt (1)	$159,771	$152,975	$155,251	$ 90,077	$ 93,099
Capital lease obligations (1)	$ 12,897	$ 13,978	$ 15,060	$ 16,141	$ 17,223
Redeemable preferred stock (1)	$ 15,000	$ 16,000	$ 17,000	$ 18,000	$ 19,000
Total capitalization (excluding current portion of debt and preferred stock)	$379,236	$381,704	$379,386	$311,454	$324,499
Total assets	$521,674	$539,838	$563,959	$530,282	$531,940

(1) Excluding current portion.

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

(Dollars in thousands except amounts per share)

	Year Ended December 31		
	2001	2000	1999
Operating Revenues	$302,476	$ 333,926	$419,815
Operating Expenses			
Operation			
Purchased power	147,662	185,941	269,386
Production and transmission	24,489	26,294	22,575
Other operation	43,420	44,119	46,967
Maintenance	18,264	14,813	17,613
Depreciation	17,041	16,882	16,955
Other taxes, principally property taxes	12,739	12,264	11,308
Taxes on income	11,472	9,034	10,360
Total operating expenses	275,087	309,347	395,164
Operating Income	27,389	24,579	24,651
Other Income and Deductions			
Equity in earnings of affiliates	2,669	3,268	2,844
Allowance for equity funds during construction	59	69	-
Other (deductions) income, net	(16,614)	7,342	1,282
Provision for income taxes	2,964	(2,777)	(35)
Total other income and deductions, net	(10,922)	7,902	4,091
Total Operating and Other Income	16,467	32,481	28,742
Interest Expense			
Interest on long-term debt	12,890	14,075	10,651
Other interest	1,018	404	1,548
Allowance for borrowed funds during construction	(30)	(41)	(41)
Total interest expense, net	13,878	14,438	12,158
Net Income Before Extraordinary Charge	2,589	18,043	16,584
Extraordinary Charge, Net of Taxes	182	-	-
Net Income	2,407	18,043	16,584
Preferred Stock Dividends Requirements	1,696	1,779	1,862
Earnings Available For Common Stock	$ 711	$ 16,264	$ 14,722
Average Shares of Common Stock Outstanding	11,551,042	11,488,351	11,463,197
Basic and Diluted Share of Common Stock:			
Earnings before extraordinary charge	$.08	$1.42	$1.28
Extraordinary charge	.02	-	-
Earnings Per Basic and Diluted Share of Common Stock	$.06	$1.42	$1.28
Dividends Paid Per Share of Common Stock	$.88	$ .88	$ .88

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

(Dollars in thousands)

	Year Ended December 31		
	2001	2000	1999
Cash Flows Provided (Used) By:			
Operating Activities			
Net income	$ 2,407	$18,043	$16,584
Adjustments to reconcile net income to net cash provided by operating activities			
Extraordinary charge	182	-	-
Equity in earnings of affiliates	(2,669)	(3,268)	(2,844)
Dividends received from affiliates	2,773	4,315	2,739
Equity in earnings from non-utility investment	(6,079)	(1,223)	795
Distribution of earnings from non-utility investments	4,636	4,457	4,390
Depreciation	17,041	16,882	16,955
Regulatory asset write-off	9,000	-	-
Asset impairment charges (including tax valuation allowance)	8,905	1,000	-
Investment write-down	1,963	-	-
Amortization of capital leases	1,089	1,089	1,093
Deferred income taxes and investment tax credits	(5,083)	(3,861)	1,971
Net (deferral) and amortization of nuclear replacement energy and maintenance costs	(2,517)	6,207	(4,914)
Amortization of conservation and load management costs	3,144	5,339	6,613
Net (deferral) and amortization of restructuring costs	(1,328)	115	-
Decrease (increase) in accounts receivable and unbilled revenues	4,746	15,754	(11,138)
(Decrease) increase in accounts payable	(3,712)	(6,597)	3,315
(Decrease) increase in accrued income taxes	(1,614)	753	(2,300)
Change in other working capital items	(6,532)	3,029	588
Change in environmental reserve	(285)	(275)	68
Other, net	4,149	(892)	(2,683)
Net cash provided by operating activities	30,216	60,867	31,232
Investing Activities			
Construction and plant expenditures	(16,553)	(14,968)	(13,231)
Conservation and load management expenditures	(504)	(1,136)	(2,440)
Return of capital	641	488	186
Proceeds from sale of assets	-	-	88
Non-utility investments	(13,671)	(4,634)	(14,338)
Other investments, net	(474)	(134)	(198)
Net cash used for investing activities	(30,561)	(20,384)	(29,933)
Financing Activities			
Sale of common stock	556	534	75
Short-term debt, net	-	17	(40,585)
Long-term debt, net	9,796	(14,776)	78,674
Retirement of preferred stock	-	(1,000)	(1,000)
Common and preferred dividends paid	(11,433)	(11,888)	(11,950)
Reduction in capital lease obligations	(1,089)	(1,089)	(1,092)
Other	20	244	(11)
Net cash used for financing activities	(2,150)	(27,958)	24,111
Net (Decrease) Increase In Cash and Cash Equivalents	(2,495)	12,525	25,410
Cash and Cash Equivalents at Beginning of Year	47,986	35,461	10,051
Cash and Cash Equivalents at End of Year	$45,491	$47,986	$35,461
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$13,871	$13,862	$ 9,207
Income taxes (net of refunds)	$16,892	$15,118	$10,935
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.

(Dollars in thousands)

	December 31	
ASSETS	2001	2000
Utility Plant, at original cost	$490,137	$478,324
Less accumulated depreciation	198,087	183,828
	292,050	294,496
Construction work-in-progress	15,727	15,197
Nuclear fuel, net	852	1,283
Net utility plant	308,629	310,976
Investments and Other Assets		
Investments in affiliates, at equity	23,823	24,527
Non-utility investments	49,543	46,591
Non-utility property, less accumulated depreciation	2,401	2,172
Total investments and other assets	75,767	73,290
Current Assets		
Cash and cash equivalents	45,491	47,986
Special deposits	7	118
Accounts receivable, less allowance for uncollectible accounts ($2,071 in 2001 and $1,655 in 2000)	21,951	25,006
Unbilled revenues	16,404	17,142
Materials and supplies, at average cost	4,167	3,702
Prepayments	3,676	2,593
Other current assets	5,408	6,511
Total current assets	97,104	103,058
Regulatory Assets	32,403	45,797
Other Deferred Charges	7,771	6,717
Total Assets	$521,674	$539,838
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock equity	$183,514	$190,697
Preferred and preference stock	8,054	8,054
Preferred stock with sinking fund requirements	15,000	16,000
Long-term debt	159,771	152,975
Capital lease obligations	12,897	13,978
Total capitalization	379,236	381,704
Current Liabilities		
Current portion of preferred stock	1,000	-
Current portion of long-term debt	7,225	4,205
Accounts payable	4,796	6,407
Accounts payable – affiliates	12,092	13,523
Accrued income taxes	74	1,428
Dividends declared	2,978	2,532
Nuclear decommissioning costs	2,298	2,214
Disallowed purchased power costs	-	2,934
Other current liabilities	19,739	23,117
Total current liabilities	50,202	56,360
Deferred Credits		
Deferred income taxes	38,828	43,779
Deferred investment tax credits	5,658	6,049
Nuclear decommissioning costs	12,826	14,737
Other deferred credits	34,924	37,209
Total deferred credits	92,236	101,774
Commitments and Contingencies		
Total Capitalization and Liabilities	$521,674	$539,838

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

(Dollars in thousands)

	December 31	
	2001	2000
Common Stock Equity		
Common stock, $6 par value, authorized 19,000,000 shares; issued 11,785,848 shares	$ 70,715	$ 70,715
Other paid-in capital	47,634	45,810
Accumulated other comprehensive income	(623)	(269)
Deferred compensation plans-employee stock ownership plans	(1,097)	(358)
Treasury stock (175,165 shares and 277,868 shares, respectively, at cost)	(2,285)	(3,624)
Retained earnings	69,170	78,423
Total common stock equity	183,514	190,697
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; 160,000 shares	16,000	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	-	-
	24,054	24,054
Less current portion	1,000	-
Total cumulative preferred and preference stock	23,054	24,054
Long-Term Debt		
First Mortgage Bonds		
9.26% Series GG, due 2002	3,000	3,000
9.97% Series HH, due 2003	7,000	11,000
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 (1.65% at December 31, 2001)	5,800	5,800
New Hampshire Industrial Development Authority Bonds		
5.50%, due 2009	5,500	5,500
Connecticut Development Authority Bonds		
Variable, due 2015 (1.80% at December 31, 2001)	5,000	5,000
Other, various	22,696	8,880
	166,996	157,180
Less current portion	7,225	4,205
Total long-term debt	159,771	152,975
Capital Lease Obligations	12,897	13,978
Total Capitalization	$379,236	$381,704

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

(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, 1998	11,461,131	$70,715	$45,318	-	$(365)	$(4,234)	$67,748	$179,182
Treasury stock at cost	5,674					75		75
Net income							16,584	16,584
Other comprehensive income net of taxes					119			119
Cash dividends on capital stock:								
Common stock - $.88 per share							(10,099)	(10,099)
Cumulative preferred stock:								
Non-redeemable							(368)	(368)
Redeemable							(1,494)	(1,494)
Amortization of preferred stock issuance expenses			22					22
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
Adjustments to 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
Adjustments to 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							260	260
Balance, December 31, 2001	**11,610,683**	**$70,715**	**$47,634**	**$(1,097)**	**$(623)**	**$(2,285)**	**$69,170**	**$183,514**

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

NOTE 1 ▣ SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries.

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 its wholly owned subsidiary, Connecticut Valley Electric Company Inc.'s ("Connecticut Valley") 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. Criteria that 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 are probable.

In the third quarter of 2001, Management determined that Connecticut Valley is again subject to cost-based ratemaking and qualifies for application of SFAS No. 71. This decision was based on the favorable Court of Appeals decision of July 25, 2000, the subsequent denial of the NHPUC's petition for writ of certiorari by the United States Supreme Court on February 20, 2001 and other regulatory developments in New Hampshire during 2001. In 1998, Management had discontinued the application of SFAS No. 71 related to Connecticut Valley. For additional information see Note 12 below.

Unregulated Business Results of operations of the Company's two wholly owned non-regulated subsidiaries, Catamount Energy Corporation ("Catamount") and Eversant Corporation ("Eversant", formerly SmartEnergy Services, Inc.), are included in Other income, net in the Other Income and Deductions section of the Consolidated Statement 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 in accordance with industry practice. Project viability is obtained when it becomes probable that costs incurred will generate future economic benefits sufficient to recover these costs. Investments in joint ventures and in partnerships over which Catamount does not have a controlling financial interest are accounted for using the equity method. Under this method, Catamount records its ownership share of the net income or loss of each venture in the accompanying consolidated financial statements.

In the fourth quarter of 2001, Catamount recorded asset impairment charges related to four of its investments in non-regulated energy generation projects, in accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" ("SFAS No. 121"). For additional information see Note 3 below.

Revenues Estimated unbilled revenues are recorded at the end of each quarterly accounting period. For 2000 and 1999, operating revenues include \$22.2 million and \$100.1 million, respectively, related to the Alliance with Virginia Power, which was effectively terminated by the Company during the third quarter of 1999 with related revenues ending in December 2000.

Maintenance Maintenance and repairs, including replacements not qualifying as retirement units of property, are charged to maintenance expense. Replacements of retirement units are charged to utility plant. The original cost of units retired plus the cost of removal, less salvage, is charged to the accumulated provision for depreciation.

Depreciation The Company uses the straight-line remaining life method of depreciation. Total depreciation expense was 3.54%, 3.57% and 3.53% of the cost of depreciable utility plant for each of the years 1999 through 2001, 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. Investment tax credits associated with non-utility plant are recognized as income in the year realized. Valuation allowances are provided when necessary against certain deferred tax assets.

Allowance for Funds During Construction Allowance for funds used during construction or AFDC is the cost during the period of construction of debt and equity funds used to finance construction projects. The Company capitalizes AFDC as a 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. AFDC equity represents a current non-cash credit to earnings, recoverable over the life of the property. The AFDC rates used by the Company were 5.52%, 9.30% and 9.40% for the years 1999 through 2001, respectively.

Regulatory Assets Certain costs are deferred and amortized in accordance with authorized or expected ratemaking treatment. The major components of regulatory assets reflected in the Consolidated Balance Sheets as of December 31, are as follows (dollars in thousands):

	2001	2000
Conservation and load management (a)	\$ 4,633	\$10,212
Restructuring costs	59	2,472
Nuclear refueling outage costs (a)	4,445	1,928
Income taxes (b)	6,770	7,047
Year 2000 costs and technology initiatives	-	2,322
Dismantling costs (c):		
Maine Yankee nuclear power plant	10,612	11,505
Connecticut Yankee nuclear power plant	4,513	5,446
Hydro-Quebec arbitration costs, net of deseasonalized revenue impact for 2000	-	2,531
Unrecovered plant and regulatory study costs	1,310	1,510
Other regulatory assets	61	824
	\$32,403	\$45,797

(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. See Note 2 below for discussion of the costs associated with the discontinued operations of the nuclear power plants.

As a result of the June 26, 2001 approved rate order, the Company wrote off $9.0 million (pre-tax) of regulatory assets, in the second quarter of 2001, related to Conservation and Load Management ("C&LM") costs, Year 2000 costs and technology initiatives, restructuring costs, and other costs as agreed to with the PSB. In addition, the Company agreed that all amounts collected based on the award issued by the Hydro-Quebec arbitration panel would be applied first to reduce the balance of the deferred costs related to the ice storm arbitration, with the remaining balance applied to reduce other regulatory asset accounts as specified by the Vermont Department of Public Service ("DPS") and approved by the PSB. See Note 12 for discussion of the Vermont rate case settlement.

In July 2001, the Company received its share of the settlement with Hydro-Quebec of $4.3 million, and applied approximately $2.7 million to the remaining balance of the deferred costs related to the ice storm arbitration. 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 of the Hydro-Quebec settlement to remaining regulatory assets, which agreement is subject to approval by the PSB. Currently, the remaining $1.6 million balance is included as a deferred credit on the Company's Consolidated Balance Sheet. See Note 13 for discussion of the Hydro-Quebec contract.

During the first six months of 2001, Vermont Yankee and Millstone Unit #3 had scheduled refueling outages. During regular nuclear refueling outages, in accordance with ratemaking treatment, the incremental costs attributable to replacement energy purchased from ISO-New England or other parties in New England and maintenance costs are deferred and amortized ratably to expense until the next regularly scheduled refueling outage.

Purchased Power The Company records the annual cost of power obtained under long-term contracts as operating expenses. Since these contracts, more fully described in Note 13, do not convey to the Company the right to use 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. As such, the Company has recorded a liability for its commitment under the Phase I and II arrangements and recognized an asset for the right to use these facilities. Purchased power in 2000 and 1999 includes $22.0 million and $100.6 million, respectively, related to the Alliance with Virginia Power, which was effectively terminated by the Company during the third quarter of 1999 with related purchases ending in December 2000.

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 and 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 market value of the long-lived asset. Based on Management's review, certain of Catamount's assets are impaired at December 31, 2001. See Note 3 to the Consolidated Financial Statements for further discussion.

Use of Estimates The preparation of financial statements in accordance with generally accepted accounting principles 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.

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

Statement of Cash Flows The Company considers all highly liquid investments with an original maturity of three months or less when acquired to be cash equivalents.

NOTE 2 □ INVESTMENTS IN AFFILIATES

The Company uses the equity method to account for its investments in the following companies (dollars in thousands):

		December 31	
	Ownership	2001	2000
Nuclear generating companies:			
Vermont Yankee Nuclear Power Corporation (1)	31.3%	$16,818	$16,863
Connecticut Yankee Atomic Power Company	2.0%	1,349	1,501
Maine Yankee Atomic Power Company	2.0%	1,257	1,400
Yankee Atomic Electric Company	3.5%	28	283
		19,452	20,047
Vermont Electric Power Company, Inc.:			
Common stock	56.8%	3,710	3,575
Preferred stock		661	905
		$23,823	$24,527

(1) The Company's ownership percentage in Vermont Yankee has changed to 33.23% in the first quarter of 2002 related to the buy-back of shares held by minority owners of the plant, which is explained below.

Each sponsor of the nuclear generating companies is obligated to pay an amount equal to its entitlement percentage of fuel, operating expenses (including decommissioning expenses) and cost of capital and is entitled to a similar share of the power output of the plants. The Company's entitlement percentages are identical to the ownership percentages except that its entitlement percentage in Vermont Yankee is 35%. The Company is obligated to contribute its entitlement percentage of the capital requirements of Vermont Yankee and Maine Yankee and has a similar, but limited, obligation to Connecticut Yankee. The Company is responsible for paying its entitlement percentage of decommissioning costs for Vermont Yankee, Connecticut Yankee, Maine Yankee and Yankee Atomic.

Vermont Yankee

Vermont Yankee's current decommissioning cost study is based on a 1994 site study stated in 1993 dollars. The FERC-approved settlement agreement allowed $312.7 million as the estimated decommissioning cost. Based on the study's assumed cost escalation rate of 4.25% per annum and an expiration of the plant's operating license in the year 2012, the estimated current cost of decommissioning is $471.1 million at the end of 2001 and, at the end of 2012, is approximately $721.8 million. At December 31, 2001, the market value of the Vermont Yankee Decommissioning Trust Fund was approximately $297.1 million. Based on the total estimated costs to decommission the plant in 2012, the Company's decommissioning obligation is approximately $148.7 million, which represents the value of payments and accrued earnings in the decommissioning trust fund to accomplish the level of funding required at 2012.

Under the FERC-approved settlement agreement, Vermont Yankee was required to file with the FERC an updated decommissioning cost study by April 1, 1999. On May 13, 1999, in light of the ongoing discussions involving the possible sale of the Vermont Yankee nuclear power plant, the FERC approved a settlement agreement extending the required filing date. If the plant is not sold, Vermont Yankee will need to submit a new decommissioning filing to the FERC. The sale of the plant would transfer responsibility for decommissioning the plant to the new owner and make a revised schedule of decommissioning unnecessary.

On February 14, 2001, the PSB issued its Order Dismissing Petition in Docket No. 6300, the proceeding in which the Company, along with Green Mountain Power ("GMP"), Vermont Yankee and AmerGen Energy Company ("AmerGen") sought PSB approval of the sale of the Vermont Yankee nuclear plant to AmerGen. In this Order, the PSB determined that the proposed purchase price, as filed in November 2000, pursuant to a Memorandum of Understanding, did not reflect the fair market value of the plant and, therefore, the sale did not promote the general good of the State of Vermont. This ruling was consistent with the Company's position. The PSB dismissed the petition for approval in March 2001. The management of Vermont Yankee subsequently concluded that selling the plant at auction would provide the greatest benefit to the owners and consumers. The investment banking firm of JPMorgan was retained by Vermont Yankee as the exclusive financial advisor for the auction.

As a result of issues raised related to the cancelled AmerGen sale, Vermont Yankee reached an agreement in principle with the Vermont Yankee sponsors and their secondary power purchasers, the DPS and the FERC staff that reduces the Vermont Yankee cost of service the sponsors and the secondary purchasers will expect to pay through 2012. The agreement is reflected in billings to sponsors and secondary purchasers effective July 2001. The FERC approved the agreement on September 13, 2001.

On August 15, 2001, Vermont Yankee announced that a sales agreement had been reached with Entergy Corporation ("Entergy") for $180 million, representing $145 million for the plant and related assets and $35 million for nuclear fuel. Entergy will also assume decommissioning liability for the plant and its decommissioning trust fund. The agreement includes a purchase power contract with prices that generally range from 3.9 cents to 4.5 cents per kilowatt-hour subject to a "low-market adjuster" that protects the current Vermont Yankee owner-utilities, including the Company and its power consumers, in the event power market prices drop significantly. On September 27, 2001, the Company filed testimony with the PSB in support of the sale. In an order entered October 26, 2001, the PSB granted intervention to several parties that the Company did not oppose, and established a schedule which provides for discovery, hearings and final briefing by April 29, 2002. Certain of the intervenors were secondary purchasers of Vermont Yankee power, which were seeking adjustments in their power purchase contracts, and stockholders of Vermont Yankee, which were asserting dissenters' rights. On January 16, 2002, Vermont Yankee announced that it had reached an agreement with the secondary purchasers and had purchased back the shares held by the minority stockholders; these parties have requested to withdraw from the PSB proceeding.

On January 7, 2002, the DPS and the remaining intervenors prefiled their direct testimony in the PSB proceeding. Initial hearings occurred during the first week of February 2002 with prefiled rebuttal testimony due on February 25, 2002, and rebuttal hearings March 18 through March 22, 2002. The current schedule in the PSB proceeding could permit a closing, if the sale is approved, by the end of July 2002. The Company cannot predict the outcome of the proceedings.

The sale is also subject to other regulatory approvals including the Nuclear Regulatory Commission and the Securities and Exchange Commission.

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% of its required system capacity.

Maine Yankee's total estimated decommissioning costs, based on a 1998 study, amounts to approximately $536.0 million in 1998 dollars. In January 2002, Maine Yankee and Federal Insurance agreed on a settlement of the pending litigation arising from contractor performance when the original contractor, Stone and Webster, went into bankruptcy. A settlement payment of $44.0 million has been deposited into the Maine Yankee Decommissioning Trust Fund. Future payments for the closing, decommissioning and recovery of the remaining investment in Maine Yankee, including the insurance settlement, are currently estimated to be approximately $494.2 million; the Company's share is expected to be approximately $9.9 million to be paid over the period 2002 through 2008.

On January 19, 1999, Maine Yankee and the active intervenors filed an Offer of Settlement with the FERC which the FERC has approved. As a result, all issues raised in the FERC proceeding, including recovery of anticipated future payments for closing, decommissioning and recovery of the remaining investment in Maine Yankee are resolved. Also resolved are issues raised by the secondary purchasers, who purchased Maine Yankee power through agreements with the original owners, limiting the amounts they will pay for decommissioning the Maine Yankee plant and settling other points of contention affecting individual secondary purchasers.

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 3.0% of its required system capacity.

Connecticut Yankee's estimated decommissioning costs, based on a July 2000 settlement with the FERC and the intervenors, amounts to approximately $569.0 million in January 2000 dollars. The settlement rates became effective September 1, 2000, following the FERC order of July 26, 2000. Future payments for the closing, decommissioning and recovery of the remaining investment in Connecticut Yankee are currently estimated to be $226.6 million; the Company's share is expected to be approximately $4.5 million to be paid over the period 2002 through 2007.

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% of its system capacity. As of July 2000, Yankee Atomic had collected from its sponsors sufficient funds, based on a current forecast, to complete the decommissioning effort and to recover all other FERC-approved costs of service. Therefore, Yankee Atomic discontinued billings to its sponsors pending the need to increase or decrease the funds available for the completion of its financial obligations, including decommissioning. Such a change would require a FERC review and approval.

Maine Yankee, Connecticut Yankee and Yankee Atomic Decommissioning Costs

Currently, costs billed to the Company by Maine Yankee and Connecticut Yankee, including a provision for ultimate decommissioning of the units, are being collected from the Company's customers through existing retail and wholesale rate tariffs. As of December 31, 2000, the Company has completed its obligation for decommissioning costs based on current estimates related to Yankee Atomic. The Company's share of remaining costs with respect to Maine Yankee and Connecticut Yankee's decisions to discontinue operation were estimated to be $10.6 million and $4.5 million, respectively, at December 31, 2001. These amounts are subject to ongoing review and revisions, and are reflected in the accompanying Consolidated Balance Sheet both as regulatory assets and nuclear dismantling liabilities (current and non-current). In the first quarter of 2002, the Company plans to revise its estimated share of remaining costs related to Maine Yankee to reflect the impacts of the insurance settlement described above.

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. This 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, Connecticut Yankee and Yankee Atomic decommissioning costs will be recovered through the regulatory process and, 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.

Nuclear Insurance

The Price-Anderson 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 Price-Anderson Act, but subject to Congressional approval. The first $200 million of liability coverage is the maximum provided by private insurance. The Secondary Financial Protection Program is a retrospective insurance plan providing additional coverage up to $9.3 billion per incident by assessing $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 $10.0 million per incident per nuclear unit in any one year. The maximum assessment is adjusted at least every five years to reflect inflationary changes. The Price-Andersen Act has been renewed three times since it was first enacted in 1957. The Act is set to expire in August 2002 and Congress is currently considering reauthorization of this legislation. Currently the Company's interests in the nuclear power units are such that it could become liable for an aggregate of approximately $3.7 million of such maximum assessment per incident per year.

Vermont Yankee

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

Earnings	2001	2000	1999
Operating revenues	$178,840	$178,294	$208,812
Operating income	$ 11,983	$ 16,144	$ 14,932
Net income	$ 6,119	$ 6,583	$ 6,471
Company's equity in net income	$ 1,912	$ 2,052	$ 2,022

	December 31	
Investment	2001	2000
Current assets	$ 35,344	$ 37,186
Non-current assets	688,471	669,798
Total Assets	723,815	706,984
Less:		
Current liabilities	64,082	72,156
Non-current liabilities	605,558	580,507
Net assets	$ 54,175	$ 54,321
Company's equity in net assets	$ 16,818	$ 16,863

Included in Vermont Yankee's revenues shown above are sales to the Company of $56.1 million, $55.5 million and $65.0 million for 2001, 2000 and 1999, respectively. These amounts are reflected as purchased power, net of deferrals and amortization, in the accompanying Consolidated Statement of Income.

VELCO

Vermont Electric Power Company, Inc. ("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 56.8% of VELCO's outstanding common stock, the Four-Party Agreement effectively restricts the Company's control of VELCO. Therefore, VELCO's financial statements have not been consolidated. The Four-Party Agreement continued in full force and effect until midnight, June 30, 1985, and was extended thereafter as follows until June 30, 1986, with an automatic renewal from year to year unless, at least 90 days prior to any succeeding anniversary, any party were to notify the other parties in writing that it desired to terminate the agreement as of such anniversary. By an Amendment to the 1985 Four-Party Agreement dated February 1, 1987, the Agreement continued until May 1, 1987 and thereafter for additional two-year terms, unless at least 90 days prior to any two-year anniversary, any party were to notify the other parties in writing that it desires to terminate the Agreement as of such anniversary. No such notification has been filed by the parties. The Company also owns 46.6% of VELCO's outstanding preferred stock, $100 par value.

In December 1985, the Company, VELCO and the two other major distribution companies entered into the 1985 Option Agreement (as amended) for the purpose of modifying the terms of an option to purchase certain facilities owned by VELCO, but located in the individual company's service territory, which were originally outlined in the Four-Party Agreement. The option was extended from time to time and expired on December 31, 2001. The Company and the other parties to the Option Agreement are currently negotiating an extension to the Option Agreement.

Summarized financial information for VELCO is as follows (dollars in thousands):

Earnings	2001	2000	1999
Transmission revenues	$19,785	$17,711	$16,935
Operating income	$ 3,588	$ 2,684	$ 2,633
Net income	$ 1,052	$ 1,257	$ 1,221
Company's equity in net income	$ 585	$ 645	$ 638

	December 31	
Investment	2001	2000
Current assets	$21,650	$22,713
Non-current assets	67,720	61,098
Total assets	89,370	83,811
Less:		
Current liabilities	22,026	32,840
Non-current liabilities	59,423	42,721
Net assets	$ 7,921	$ 8,250
Company's equity in net assets	$ 4,371	$ 4,480

Included in VELCO's revenues shown above are transmission services to the Company (reflected as production and transmission expenses in the accompanying Consolidated Statement of Income) amounting to $10.5 million, $9.8 million and $8.6 million for 2001, 2000 and 1999, respectively.

NOTE 3 □ NON-UTILITY INVESTMENTS

Catamount

The Company's wholly owned subsidiary, Catamount Energy Corporation, a subsidiary of Catamount Resources Corporation, invests through its wholly owned subsidiaries, in non-regulated, wind energy-supply projects in North America and Western Europe. Catamount's after-tax loss for 2001 was $8.7 million, primarily resulting from fourth quarter 2001 asset impairment charges related to four of its investments as a result of writing down two assets held for sale to estimated sales value (Gauley River Power Partners, L.P. and Fibrothetford Limited) and issues concerning the future viability of two other operating projects (Rupert Cogeneration and Glenns Ferry Cogeneration). After-tax earnings were $0.7 million and $2.1 million for 2000 and 1999, respectively.

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 2001	Investment December 31 2000
Rumford Cogeneration	Maine	85 mW	Coal/Wood	1990	15.1%	$18,086	$15,858
Ryegate Associates	Vermont	20 mW	Wood	1992	33.1%	6,544	6,392
Appomattox Cogeneration	Virginia	41 mW	Coal/Biomass Black liquor	1982	25.3%	6,560	4,699
Rupert Cogeneration Partners	Idaho	10 mW	Gas	1996	50.0%	-	1,931
Glenns Ferry Cogeneration	Idaho	10 mW	Gas	1996	50.0%	-	1,722
Fibrothetford Limited	England	38.5 mW	Biomass	1998	44.7%	2,529	6,258
Heartlands Power Limited	England	98 mW	Gas	1999	50.0%	6,377	7,360
Gauley River Power Partners	West Virginia	80 mW	Water	2001	50.0%	8,500	(100)
DK Burgerwindpark Eckolstadt	Germany	13 mW	Wind	2000	10.0%	356	308
DK Windpark Kavelstorf GmbH&Co. KG	Germany	7.2 mW	Wind	2001	10.0%	143	139
Total						$49,095	$44,567

At December 31, 2001, Gauley River Power Partners, L.P. ("Gauley River") and Fibrothetford Limited ("Fibrothetford") were classified as held-for-sale. In the fourth quarter, in accordance with SFAS No. 121, Catamount recorded an after-tax impairment charge to earnings of $1.4 million associated with its interests in Gauley River and an after-tax impairment charge to earnings of $3.2 million associated with its interest in Fibrothetford. The Gauley River impairment was based on bids received from third parties, less estimated costs to sell. The impairment charge for Fibrothetford was based on review of expected future cash flows and expected market value of Catamount's interest given the project's current financial condition.

Although Catamount has a controlling interest in Gauley River, this investment has not been consolidated in the accompanying financial statements since it is Management's intent to sell this project and therefore control is considered temporary. For equity accounting purposes, the Gauley River investment is treated as a 100% ownership investment. Included in the $8.5 million December 31, 2001 investment balance is a $1.0 million equity investment which will be funded by March 31, 2002.

In the fourth quarter of 2001, Catamount recorded impairment charges for all of its interests in the Glenns Ferry and Rupert projects for a total after-tax charge of $3.0 million. 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. The steam hosts are actively seeking resolution of their current financial issues; however, Management cannot predict whether they will ultimately be successful. Also see Note 7, Long-term debt, for additional information.

Eversant

Eversant, also a subsidiary of Catamount Resources Corporation, invests in unregulated energy and service-related businesses. Eversant had a 13.4% ownership interest, on a fully diluted basis, in Home Service Store ("HSS") as of December 31, 2001. HSS establishes a network of affiliate contractors who perform home maintenance repair and improvements via membership. HSS began operations in 1999 and is subject to risks and challenges similar to a company in the early stage of development. HSS launched a Commercial Services division in 2001, which meets the needs of small businesses, building owners and property managers. In May 2001, Eversant entered into a convertible loan agreement with HSS and Jupiter Capital ("Jupiter"). Under the agreement, Eversant loaned HSS $2.0 million and Jupiter loaned HSS $5.0 million, which, along with current debt balances and accrued interest, was converted to preferred securities when HSS received an additional cash investment from Jupiter in August 2001. In September 2001, Eversant recorded a $1.2 million after-tax write-down of its investment in HSS to fair market value. Eversant has previously recorded losses of $9.0 million related to its investment in HSS. At year end, Jupiter committed, based upon continued satisfactory operating progress, to provide an additional $5.0 million in funding to the business over time. The first $1.0 million was invested in December 2001 and Jupiter received options to acquire up to an aggregate of $4.0 million in preferred securities. In January 2002, Jupiter invested an additional $1.0 million and predicts that an additional $2.0-$3.0 million in funding above the $5.0 million may be required and they are currently talking to other parties about providing this capital. Eversant's fully diluted ownership position after the $5.0 million Jupiter investment would be 12.6%.

Eversant's share of the HSS losses for 2001 was zero as the Company's equity investment was reduced to zero as a result of losses incurred to date. As of December 31, 2001, Eversant has a preferred equity investment in HSS of $1.4 million, recorded at estimated fair value.

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 markets and sells 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. The Company does not expect a material liability related to the decision and is currently in discussions with Westfalia-Surge regarding this matter. The SmartDrive Control product has generated approximately 75% of the sales revenue of AgEnergy. AgEnergy's revenues represent approximately $0.4 million of the total Eversant revenues of approximately $2.4 million, on an annual basis.

Overall, Eversant incurred net losses of $2.1 million, $2.3 million and $2.9 million for 2001, 2000 and 1999, respectively.

NOTE 4 ■ COMMON STOCK

Through a common stock repurchase program that was suspended in 1997, the Company purchased from time to time 362,447 shares of its common stock in open market transactions at an average price of $13.04 per share. These transactions, net of 187,282 shares sold in connection with the Company's stock option plans, are recorded as treasury stock, at average cost, in the Company's Consolidated Balance Sheets.

NOTE 5 ■ REDEEMABLE PREFERRED STOCK

The 8.30% Dividend Series Preferred Stock is redeemable at par through a mandatory sinking fund in the amount of $1.0 million per annum and, at its option, the Company may redeem at par an additional non-cumulative $1.0 million per annum. Since the Company's redeemable preferred stock was issued in a private placement, it is not practicable to estimate the fair value.

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 that authorized the granting of options with respect to 1,375,875 shares of the Company's common stock. Options are granted at prices not less than 100% of the fair market value at the date of the option grant and the maximum term of an option may not exceed five and ten years for non-employee directors and key employees, respectively. Shares available for future grants under the 1997, 1998 and 2000 stock option plans were 254,440 at December 31, 2001. No additional grants may be given under the 1988 and 1993 plans. Option activity during the past three years was as follows:

	Average Option Price	Stock Options
Options outstanding at December 31, 1998	$15.4649	516,000
Options exercised	10.9375	(2,250)
Options granted	10.5742	95,860
Options expired	18.0476	(24,750)
Options outstanding at December 31, 1999	$14.5714	584,860
Options exercised	10.7840	(23,700)
Options granted	10.7626	100,550
Options expired	15.4596	(128,725)
Options outstanding at December 31, 2000	$13.8067	532,985
Options exercised	12.4356	(98,550)
Options granted	16.1295	121,150
Options expired	18.6255	(31,500)
Options outstanding at December 31, 2001	$13.6050	524,085

The price range of options outstanding at December 31, 2001 is $10.5625 to $24.3125. The weighted average remaining contractual life at December 31, 2001 is 6.83 years and the weighted average exercise price is $13.6050. Exercisable options at December 31, 2001 total 494,585 and the weighted average exercise price is $13.5794.

The Company accounts for these plans under Accounting Principles Board Opinion No. 25 ("APB 25"), under which no compensation cost has been recognized. Under SFAS No. 123, "Accounting for Stock-Based Compensation," all awards granted must be recognized in compensation cost. Had compensation cost for these plans been determined consistent with SFAS No. 123, the Company's net income and earnings per share of common stock would have been reduced to the following pro forma amounts as follows (dollars in thousands, except per share amounts):

		2001	2000	1999
Net Income				
	As reported	$2,407	$18,043	$16,584
	Pro forma	$2,289	$17,959	$16,518
Earnings per share of common stock				
	As reported	$.06	$1.42	$1.28
	Pro forma	$.05	$1.41	$1.27

The Company chose the binomial model to project an estimate of appreciation of the underlying shares of the stock during the respective option term. The average assumptions used were as follows:

	2001	2000	1999
Volatility	.3328	.2872	.2982
Risk-free rate of return	5.75%	6.50%	5.50%
Dividend yield	7.42%	7.32%	7.26%
Expected life in years	5-10	5-10	5-10

Restricted Stock Plans

Annual Incentive Program

Restricted stock performance awards have been granted to certain executive officers for the Company's annual Management Incentive Plan, under the 1997 Restricted Stock Plan for Non-employee Directors and Key Employees ("Restricted Plan"), including dividends and voting rights. Restricted stock was granted to non-employee directors for 50% of their annual retainer.

Recipients are not required to provide consideration to the Company under the Restricted Plan, other than rendering service, and have the right to vote the shares and to receive dividends under the Restricted Plan.

In accordance with APB 25, compensation cost is recognized for Restricted Plan shares, over the applicable vesting period, for the fair value of the restricted stock awarded, which is its market value without restrictions at the date of grant. Because this type of plan is classified as a variable plan, interim estimates of compensation are required based on a combination of the then-fair market value of the stock as of the end of the reporting period and the extent or degree of compliance with the performance criteria.

A total of 5,813 Restricted Plan shares were issued at an average market value of $15.63 in 2001, 17,475 shares at an average market value of $10.64 in 2000 and 3,424 shares at an average market value of $11.67 in 1999. These awards are recorded at the market value on the date of grant. A total of 1,660 shares were forfeited at an average market value of $10.99 in 2001. Initially, the total market value of the shares is treated as deferred compensation and is charged to expense over the respective vesting periods.

Restricted Plan stock expense was $97,161 for 2001, $74,395 for 2000 and $39,968 for 1999.

Long-term Incentive Plan

Restricted performance shares have been awarded for the Company's three-year vesting, Long-Term Incentive Plan, for executive officers, under the 1999, 2000 and 2001 Performance Share Incentive Plans ("Performance Plans").

The restricted stock awards under the Performance Plans will vest only if the Company achieves certain financial goals over three-year performance cycles. Recipients are not required to provide consideration to the Company under the Performance Plans, other than rendering service.

Under APB No. 25, for Performance Plan shares, adjustments are made to expense for changes in market value, achievement of financial goals and changes in employment, prior to completion of the performance cycle. Initially, the total market value of the shares is treated as deferred compensation and is charged to expense over the respective performance cycles.

Performance Plan stock compensation charged to expense was $1,014,851, $200,712 and $0 for the years 2001, 2000 and 1999, respectively.

NOTE 7 ■ LONG-TERM DEBT AND SINKING FUND REQUIREMENTS

Utility

On July 30, 1999, the Company sold $75.0 million aggregate principal amount of 8 1/8% Second Mortgage Bonds due 2004 at a price of 99.915%.

Based on outstanding debt at December 31, 2001, the aggregate amount of utility long-term debt maturities and sinking fund requirements are $7.0 million, $10.5 million, $75.0 million, $0.0 million and $0.0 million for the years 2002 through 2006, respectively. Substantially all Vermont utility property and plant is subject to liens under the First and Second Mortgage Bonds.

The Company's long-term debt arrangements contain financial and non-financial covenants. At December 31, 2001, the Company was in compliance with all debt covenants related to its various debt agreements.

Financial obligations of the Company's subsidiaries are non-recourse to the Company. On April 25, 2001, the Company sought and, in June 2001, the Company received unanimous approval from its First Mortgage Bondholders to enter into a 42nd Supplemental Indenture to the Company's Mortgage dated October 1, 1929 (the "First Mortgage") to exclude its wholly owned non-regulated subsidiary, Catamount Resources Corporation and its subsidiaries (currently Catamount and Eversant), from the term "subsidiary" under the Mortgage. The 42nd Supplemental Indenture (amendment) eliminates the possibility of cross defaults under the First Mortgage occasioned by a default on the indebtedness of Catamount Resources Corporation or its subsidiaries. Additionally, the amendment imposes limitations on the level of the Company's future investment in non-regulated subsidiaries.

Non-Utility

In 1998, Catamount replaced its $8.0 million credit facility with a $25.0 million revolving credit/term loan facility, maturing November 2006, which provides for up to $25.0 million in revolving credit loans and letters of credit, of which $21.3 million was outstanding at December 31, 2001. 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, 2001, the aggregate amount of Catamount's long-term debt maturities are $0.0 million, $3.2 million, $4.2 million, $5.0 million and $9.1 million for the years 2002 through 2006, respectively. Catamount's long-term debt contains financial and non-financial covenants. At December 31, 2001, Catamount was in compliance with all covenants under the revolver except that Catamount's capital expenditures exceeded budget by an immaterial amount, which was waived by the lender in February 2002.

In 1999, SmartEnergy Water Heating Services, Inc. ("SEWHS"), a wholly owned subsidiary of Eversant, secured a $1.5 million seven-year term loan with Bank of New Hampshire with an outstanding balance of $1.1 million at December 31, 2001. The interest rate is fixed at 9.5% per annum. Based on outstanding debt at December 31, 2001, the aggregate amount of SEWHS's long-term debt maturities are $0.2 million, $0.2 million, $0.2million, $0.3 million and $0.2 million for the years 2002 through 2006, respectively. SEWHS's long-term debt contains financial and non-financial covenants. At December 31, 2001, SEWHS was in compliance with all debt covenants related to its various debt agreements.

NOTE 8 ■ SHORT-TERM DEBT

The Company had no short-term debt outstanding at December 31, 2001 or at December 31, 2000.

The Company has an aggregate of $16.9 million of letters of credit which support three series of Industry Development/Pollution Control Bonds, with termination dates of May 31, 2002. The Company has begun the process of extending these letters of credit to August 31, 2003 with Citizens Bank of Massachusetts. These letters of credit are secured by a first mortgage lien on the same collateral supporting the Company's first mortgage bonds.

NOTE 9 ■ FINANCIAL INSTRUMENTS

The estimated fair values of the Company's financial instruments at December 31, 2001 and 2000 are as follows (dollars in thousands):

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	$ 8,054	$ 3,815	$ 8,054	$ 3,695
Preferred stock subject to mandatory redemption	$16,000	$16,000	$16,000	$16,000
Long-term debt				
First mortgage bonds	$53,000	$52,259	$57,000	$58,381
Second mortgage bonds	$75,000	$76,163	$75,000	$74,432
Other long-term debt	$38,996	$38,996	$25,180	$25,180

Cash and Cash Equivalents: The carrying amounts approximate fair value because of the short maturity of those instruments.

Preferred stock and long-term debt: The fair value of the Company's fixed rate securities is estimated based on the quoted market prices for the same or similar issues or on the 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.

The Company believes that any excess or shortfall in the fair value relative to the carrying value of the Company's financial instruments, if they were settled at amounts approximating those above, would not result in a material impact on the Company's financial position or results of operations.

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 benefit payments or a lump sum amount. The Company's funding policy is to contribute at least the statutory minimum to a trust. The Company is not required by its union contract to contribute to multi-employer plans.

The Company elected to change the measurement date of pension obligations and related plan assets from December 31 to September 30 in 2000. This was not considered material enough to present in the Consolidated Statement of Income as a change in accounting principle.

The following table sets forth the funded status of the pension plan and amounts recognized in the Company's Consolidated Balance Sheets and Statement of Income (dollars in thousands):

	December 31 2001	2000
Change in pension benefit obligation		
Benefit obligation at beginning of year (January 1)	$ 64,382	$ 54,172
Service cost	2,138	1,901
Interest cost	5,046	4,614
Actuarial loss	3,699	5,952
Transfers	-	19
Benefits paid	(4,024)	(2,276)
Projected pension benefit obligation as of measurement date	$ 71,241	$ 64,382
Measurement date	September 30	September 30

	2001	2000
Change in pension plan assets		
Fair value of plan assets (primarily equity and fixed income securities) at beginning of year (January 1)	$ 80,202	$ 79,834
Actual return on plan assets	(10,549)	2,625
Employer contribution	-	-
Transfers	-	19
Benefits paid	(4,024)	(2,276)
Fair value of pension plan assets (primarily equity and fixed income securities) as of measurement date	$ 65,629	$ 80,202
Measurement date	September 30	September 30

	2001	2000
Reconciliation of funded status		
Benefit obligation	$(71,241)	$(64,382)
Fair value of assets	65,629	80,202
Funded status	(5,612)	15,820
Unrecognized net transition asset	(437)	(582)
Unrecognized prior service cost	1,703	1,893
Unrecognized net actuarial gain	(4,942)	(26,211)
Accrued pension cost	(9,288)	(9,080)
FAS 71 regulatory asset (1997 VERP)	25	933
Effective (accrued) pension cost	$ (9,263)	$ (8,147)

	2001	2000	1999
Net pension costs include the following components			
Service cost	$2,138	$1,901	$1,854
Interest cost	5,046	4,614	4,035
Expected return on plan assets	(6,244)	(5,873)	(5,081)
Amortization of prior service cost	191	191	191
Recognized net actuarial gain	(776)	(550)	-
Amortization of transition asset	(146)	(146)	(146)
Supplemental adjustment for amortization of FAS 71 Regulatory asset (1994 VERP)	-	-	37
Supplemental adjustment for amortization of FAS 71 Regulatory asset (1997 VERP)	466	466	466
Accelerated amortization of FAS 71 Regulatory asset (1997 VERP)	441	-	-
Net periodic pension cost	1,116	603	1,356
Less amount allocated to other accounts	28	21	107
Net pension costs expensed	$1,088	$ 582	$1,249

Assumptions used in calculating pension costs were as follows:

	December 31 2001	2000
Weighted average discount rates	7.25%	7.75%
Expected long-term return on assets	8.50%	8.50%
Rate of increase in future compensation levels	4.50%	4.50%
Measurement date	September 30	September 30

The Company 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 Company elected to change the measurement date of postretirement medical plan obligations and related plan assets from December 31 to September 30 in 2000. This was not considered material enough to present in the Consolidated Statement of Income as a change in accounting principle.

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets and Statement of Income in accordance with SFAS No. 106 (dollars in thousands):

	December 31	
	2001	2000
Change in postretirement benefit obligation		
Benefit obligation at beginning of year (January 1)	$ 14,800	$ 13,278
Service cost	243	183
Interest cost	1,114	984
Actuarial loss	2,874	1,058
Benefits paid	(2,949)	(703)
Projected postretirement benefit obligation as of measurement date	$ 16,082	$ 14,800
Measurement date	September 30	September 30

	2001	2000
Change in postretirement plan assets		
Fair value of plan assets (fixed income securities) at beginning of year (January 1)	$ 1,075	$ 1,733
Actual return on plan assets	31	25
Employer contribution	2,752	20
Benefits paid	(2,949)	(703)
Fair value of postretirement plan assets (fixed income securities) as of measurement date	$ 909	$ 1,075
Measurement date	September 30	September 30

	2001	2000
Reconciliation of funded status		
Benefit obligation	$(16,082)	$(14,800)
Fair value of assets	909	1,075
Company contributions between measurement date and fiscal year-end	3,584	906
Funded status	(11,589)	(12,819)
Unrecognized net transition obligation	2,814	3,070
Unrecognized net actuarial loss	6,003	3,193
Accrued postretirement benefit cost	(2,772)	(6,556)
FAS 71 regulatory asset (1997 VERP)	25	914
Effective (accrued) postretirement benefit cost	$ (2,747)	$ (5,642)

	2001	2000	1999
Net postretirement benefit costs include the following components			
Service cost	$ 243	$ 183	$ 214
Interest cost	1,114	984	892
Expected return on plan assets	(102)	(100)	(87)
Recognized net actuarial loss	135	51	93
Amortization of transition obligation	256	256	256
Supplemental adjustment for amortization of FAS 71 regulatory asset (1994 VERP)	-	-	37
Supplemental adjustment for amortization of FAS 71 regulatory asset (1997 VERP)	457	457	457
Accelerated amortization of FAS 71 regulatory asset (1997 VERP)	431	-	-
Net periodic benefit cost	2,534	1,831	1,862
Less amount allocated to other accounts	219	214	171
Net postretirement benefit costs expensed	$2,315	$ 1,617	$ 1,691

Assumptions used in the per capita costs of the accumulated postretirement benefit obligation were as follows:

	December 31	
	2001	2000
Per capita percent increase in health care costs:		
Pre-65	11.00%	6.00%
Post-65	10.50%	5.50%
Weighted average discount rates	7.25%	7.75%
Rate of increase in future compensation levels	4.50%	4.50%
Long-term return on assets	8.50%	8.50%
Measurement date	September 30	September 30

For measurement purposes, an 11% and 10.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2002, for pre-65 and post-65 claims costs, respectively. The rate is assumed to decrease 1% in each of the subsequent years until the ultimate trend of 6% and 5.5%, respectively, is reached.

Increasing (decreasing) the assumed health care cost trend rates by one percentage point in each year would have resulted in an increase (decrease) of $828,890 and $(727,610), respectively, in the accumulated postretirement benefit obligation as of December 31, 2001 and an increase (decrease) of about $68,397 and $(59,557), respectively, in the aggregate of the service cost and interest cost components of net periodic postretirement benefit cost for 2001.

The Company provides postemployment benefits consisting of long-term disability benefits. The accumulated postemployment benefit obligation at December 31, 2001 and 2000 of $1.1 million and $1.1 million, respectively, is reflected in the accompanying Consolidated Balance Sheets as a liability and in 2000 was offset by a corresponding regulatory asset of $0.2 million. Pursuant to an October 1994 PSB Rate Order, the Company was allowed to recover the regulatory asset over a 7 ½ year period beginning November 1, 1994 through April 30, 2002. In mid 2001, $0.1 million of the regulatory asset was written off as a result of the Company's June 26, 2001 approved rate order. The pre-tax postemployment benefit costs charged to the expense in 2001, 2000 and 1999, including insurance premiums, were $271,000, $481,000 and $281,000 respectively.

In the third quarter of 1997, the Company offered and recorded obligations related to a voluntary retirement and severance program to employees. The estimated benefit obligation for the retirement program as of December 31, 2001 is approximately $0.1 million. This amount consists of pension benefits and postretirement medical benefits. These obligations, deferred pursuant to a PSB Accounting Order dated September 30, 1997, are reflected in the accompanying Consolidated Balance Sheets both as regulatory assets and deferred credits. The unamortized balance of approximately $0.1 million at December 31, 2001 will be amortized through December 31, 2002. The majority of the regulatory asset related to the 7 ½ year transitional obligation was written off as a result of the June 26, 2001 approved rate order. See Notes 1 and 12 related to Regulatory Assets and Retail Rates, respectively, for additional information.

NOTE 11 □ INCOME TAXES

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

	Year Ended December 31		
	2001	2000	1999
Federal:			
Current	$10,625	$12,195	$ 6,760
Deferred	(3,713)	(2,542)	1,587
Investment tax credits, net	(391)	(391)	(391)
	6,521	9,262	7,956
State:			
Current	2,976	3,440	1,664
Deferred	(1,113)	(891)	775
	1,863	2,549	2,439
Total federal and state income taxes	$ 8,384	$11,811	$10,395

Federal and state income taxes charged to:			
Operating expenses	$11,472	$ 9,034	$10,360
Other income	(2,964)	2,777	35
Extraordinary loss	(124)	-	-
	$ 8,384	$11,811	$10,395

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):

	Year Ended December 31		
	2001	2000	1999
Income before income tax	$10,791	$29,854	$26,979
Federal statutory rate	35%	35%	35%
Federal statutory tax expense	3,777	10,449	9,443
Increases (reductions) in taxes Resulting from:			
Dividend received deduction	(741)	(895)	(790)
Deferred taxes on plant	147	453	453
State income taxes net of federal tax benefit	1,203	1,735	1,568
Investment credit amortization	(391)	(391)	(391)
AFDC Equity	214	209	139
Valuation Allowance	3,985	-	-
Other	190	251	(27)
Total income tax expense provided	$ 8,384	$11,811	$10,395

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):

	Year Ended December 31		
	2001	2000	1999
Deferred tax assets			
Purchased power accrual	$ -	$ 1,213	$ 1,603
Loss credit carryforwards	6,513	-	-
Accruals and other reserves not currently deductible	2,150	7,833	6,668
Retiree medical benefits	1,465	-	-
Deferred compensation and pension	5,679	5,587	5,402
Environmental costs accrual	3,811	3,928	4,249
Valuation Allowance	(3,985)	-	-
Total deferred tax assets	15,633	18,561	17,922
Deferred tax liabilities			
Property, plant and equipment	47,518	50,359	50,164
Net regulatory asset	2,777	2,913	3,485
Conservation and load management expenditures	1,890	4,222	5,445
Nuclear refueling costs	1,076	797	3,313
Other	1,200	4,049	4,146
Total deferred tax liabilities	54,461	62,340	66,553
Net deferred tax liability	$38,828	$43,779	$48,631

The Company received an accounting order from the PSB dated September 30, 1997, authorizing the Company to defer and amortize over a 20-year period beginning January 1, 1998, approximately $2.0 million to reflect the revenue requirement level of additional deferred income tax expense resulting from the enacted Vermont corporate income tax increase from 8.25% to 9.75% in 1997.

A valuation allowance has been recorded in the amount of $4.0 million to reflect Management's best estimate of loss credit carryforwards that will ultimately be utilized. All other deferred income tax assets 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.

Vermont Retail Rate Proceedings

1997 Retail Rate Case: The Company filed for a 6.6%, or $15.4 million per annum, general rate increase on September 22, 1997 to become effective June 6, 1998 to offset increasing costs of providing service. Approximately $14.3 million, or 92.9%, 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 Company's September 1997 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 made a filing 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." During February 1998, the DPS filed testimony in opposition to the Company's retail rate increase request. The DPS recommended that the PSB instead reduce the Company's then current retail rates by 2.5%, or $5.7 million. 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.

1998 Retail Rate Case: On June 12, 1998, the Company filed with the PSB for a 10.7% retail rate increase that supplanted the September 22, 1997 rate increase request of 6.6%, to be effective March 1, 1999. On October 27, 1998, the Company reached an agreement with the DPS regarding the June 1998 retail rate increase request providing for a temporary rate increase in the Company's retail rates of 4.7%, or $10.9 million on an annualized basis, beginning with service rendered on or after January 1, 1999. The agreement was approved by the PSB on December 11, 1998.

The 4.7% 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. The agreement temporarily disallowed approximately $7.4 million (based on 1999 power costs) for the Company's purchased power costs under the VJO Power Contract. As a result of the 4.7% rate increase agreement, during the fourth quarters of 1998 and 1999, the Company recorded pre-tax losses of $7.4 million and $2.9 million, respectively, for disallowed purchased power costs, representing the Company's estimated under-recovery of power costs, prior to further resolution, under the VJO Power Contract for 1999 and the first quarter of 2000, respectively. In 2000, an additional $11.5 million pre-tax loss was recorded for the estimated under-recovery of Hydro-Quebec power costs for the second, third and fourth quarters of 2000, and the first quarter of 2001. In the first quarter of 2001, an additional $2.9 million pre-tax loss was recorded for the estimated under-recovery of Hydro-Quebec power costs for the second quarter of 2001. 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 based on the favorable outcome of the Company's June 26, 2001 rate order, which is described below.

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% rate increase ($19.0 million of annualized revenues) effective July 24, 2001. The PSB suspended the rate filing and a schedule was set to review the case.

On February 9, 2001, the Vermont Supreme Court issued a decision on the Company's 1998 rate case appeal that reversed the PSB's decision on the preclusion issues and remanded the case to the PSB for further proceedings consistent with the Vermont Supreme Court's decision.

The Company's June 26, 2001 rate order, which is described below, 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.

On May 7, 2001, the Company and the DPS reached a rate case settlement that would end uncertainty over the future recovery of Hydro-Quebec contract costs, allow a 3.95 % rate increase, make the January 1, 1999 temporary rates permanent, permit a return on equity of 11% for the twelve months ending June 30, 2002 for the Vermont utility, and create new service quality standards. The Company also agreed to a second quarter $9.0 million one-time write-off ($5.3 million after-tax) of regulatory assets and a rate freeze through January 1, 2003.

On June 26, 2001, the PSB issued an order on the Company's rate case settlement with the DPS. In addition to the provisions outlined above, the approved rate order requires the Company to return up to $16.0 million to ratepayers in the event of a merger, acquisition or asset sale if such sale requires PSB approval. As a result of the rate order, the 3.95% rate increase became effective with bills rendered July 1, 2001, and in June 2001 the Company recorded a $5.3 million after-tax loss to write off certain regulatory assets as agreed to in the settlement. The Company was able to accept the 3.95% rate increase versus the 7.6% increase it requested since 1) regulatory asset amortizations will decrease approximately $3.5 million, on a twelve-month basis, due to the $9.0 million one-time write-off of regulatory assets and 2) Vermont Yankee decommissioning costs decreased approximately $1.9 million, on a twelve-month basis, after the rate case was filed as a result of an agreement in principle between Vermont Yankee and the secondary purchasers.

Deseasonalized Rates: On June 8, 2000, the PSB approved the Company's request to end the winter-summer rate differential and, therefore, the Company now has flat rates throughout a given year. Winter rates were reduced by 14.9%, while summer rates were increased by 10.5%. The rate design change was revenue neutral over a twelve-month period. The additional revenues in 2000, resulting from implementing this change in mid-year, were applied to reduce regulatory deferrals related to the Hydro-Quebec ice storm arbitration, as directed by the PSB.

New Hampshire Retail Rate/Federal Court Proceedings

Connecticut Valley's retail rate tariffs, approved by the NHPUC, contain a Fuel Adjustment Clause ("FAC") and a Purchased Power Costs 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.

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. The Court also ruled that the NHPUC cannot 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. The Court's decision was issued as a written order on May 11, 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, Public Service Company of New Hampshire ("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 judgement 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 judgement and dismissal.

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 judgement 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% 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 judgement 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 $2.0 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 is again subject to cost-based ratemaking and qualifies for the application of SFAS No. 71. This decision was based on the favorable Court of Appeals decision of July 25, 2000 and the subsequent denial of the NHPUC's petition for writ of certiorari by the United States Supreme Court on February 20, 2001 as well as other regulatory developments in New Hampshire during 2001. The application of SFAS No. 71 resulted in an extraordinary charge of $0.2 million for Connecticut Valley.

As part of its restructuring plan, the New Hampshire Legislature enacted an Electricity Consumption Tax on customers and repealed the New Hampshire Franchise Tax on utilities, both of which became effective May 1, 2001. Since the Franchise Tax, as a credit to the New Hampshire Business Profits Tax, was larger than the Business Profits Tax, the repeal of the Franchise Tax caused Connecticut Valley to incur the Business Profits Tax. The NHPUC approved a settlement that reduced base rates to remove recovery of the Franchise Tax and implemented a Business Profits Tax Percentage Adjustment that would be subject to annual revisions in order to collect the Business Profits Tax.

On December 31, 2001, the NHPUC ruled on Connecticut Valley's request for a Temporary Billing Surcharge to recover approximately $1.7 million of one-time costs primarily related to industry restructuring effective January 1, 2002. Connecticut Valley had proposed the Temporary Billing Surcharge to exactly offset a contemporaneously filed FAC/PPCA decrease of 9.3% such that a zero rate change would occur at January 1, 2002 and the 9.3% FAC/PPCA decrease would occur when the Temporary Billing Surcharge terminated in November 2002. The NHPUC affirmed its prior policy of considering recovery of costs related to industry restructuring at the time retail choice is implemented in the Connecticut Valley service area. Thus the NHPUC deferred action on all but $125,000, for which recovery was allowed through November 30, 2002.

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% rate reduction with a revenue decrease of $1.8 million.

FERC 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 $83.0 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. Absent termination of the wholesale rate schedule by mutual agreement, the earliest termination date that could presently occur pursuant to the wholesale rate schedule is December 31, 2003. The stranded cost obligation as of December 31, 2003, expressed on a net present value basis set forth in the ALJ order, is approximately $33.9 million.

The ALJ's Initial Decision is subject to review and approval by the FERC. If the Company is unable to obtain approval by the FERC, and if Connecticut Valley is forced to terminate its relationship as a wholesale customer of the Company, it is possible that the Company would be required to recognize a pre-tax loss under this contract totaling approximately $32.9 million as of December 31, 2003. The Company would also be required to write off approximately $0.9 million (pre-tax) of regulatory assets associated with its wholesale business as of December 31, 2003. If the Company obtains a FERC order authorizing the updated requested exit fee and notice of termination is given, Connecticut Valley will apply to the NHPUC to increase rates in order to pay the exit fee. The Company believes that the NHPUC must permit Connecticut Valley to raise rates to recover the cost of the exit fee. However, if Connecticut Valley is unable to recover its costs in rates, Connecticut Valley would be required to recognize the loss discussed above.

In addition to its efforts before the Court and FERC, Connecticut Valley has initiated efforts and will continue to work for a negotiated settlement with parties to the New Hampshire restructuring proceeding and the NHPUC.

An adverse resolution of the FERC and New Hampshire proceedings would have a material adverse effect on the Company's results of operations and cash flows. However, the Company cannot predict the ultimate outcome of this matter. See New Hampshire Retail Rates/Federal Court Proceedings above for additional information.

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. In 2001, under long-term contracts with these qualifying facilities, Connecticut Valley purchased 38,890 mWh, of which 96% 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.

In December 2000 and January 2001, Wheelabrator, the New Hampshire/Vermont Solid Waste District, and several Connecticut Valley residential customers filed with the NHPUC to intervene. The Office of Consumer Advocate and the NHPUC Staff are automatic parties. A Prehearing Conference was held before the NHPUC on January 4, 2001, at which time each party provided preliminary position statements with regard to the petition. In February and March 2001, the parties filed briefs on the legal issues and Wheelabrator filed a motion to dismiss. The Company cannot predict when the NHPUC will issue a decision on the legal issues or the motion to dismiss or on the outcome of this matter.

NOTE 13 ■ COMMITMENTS AND CONTINGENCIES

The Company's power supply is acquired from a number of sources including its own generating units, jointly owned units, long-term contracts and short-term purchases. The cost of power obtained from sources other than wholly and jointly owned units, including payments required to be made whether or not energy is received by the Company, is reflected as Purchased power in the Consolidated Statement of Income.

Nuclear Investments The Company has investments in, and is entitled to receive power from, four nuclear generating companies, three of which (Maine Yankee, Connecticut Yankee and Yankee Atomic) are permanently shut down. See Note 2 for a discussion of the Company's obligations related to its investment in nuclear generating companies. The Company is also a joint owner of the Millstone Unit #3 nuclear generating plant. In August 2000, the Company received a cash settlement of $5.4 million pursuant to a July 27, 2000 settlement agreement with NU resolving all issues related to arbitration and lawsuits sought to recover costs associated with the shutdown of Unit #3 in 1996. On September 15, 1999, NU announced its intent to auction its nuclear generating plants, including Unit #3. On August 7, 2000, the Connecticut Department of Public Utility Control announced that Dominion Resources, Inc. was the successful bidder in the auction. Pursuant to the terms of the settlement agreement described above, the Company participated as a potential seller in that auction. Upon notification of the sales price, the Company evaluated and declined the purchase offer. The sale to Dominion Nuclear Connecticut ("DNC"), a subsidiary of Dominion Resources, became final on March 31, 2001.

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. Under these long-term contracts, in 2001, the Company received 168,382 mWh of which 118,187 mWh is associated with the Vermont Electric Power Producers and 37,293 mWh with Wheelabrator. The Company expects to purchase approximately 197,000 mWh of independent power output in each year 2002 through 2006. Based on the forecast level of production, the total commitment in the next five years to purchase power from these independent power facilities is estimated to be $116 million, which excludes the impact of the January 28, 2002 Memorandum of Understanding described below.

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 purchase 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, the other moving utilities and the DPS requested that the PSB issue an order requiring GMP's full participation in the PSB proceeding. The PSB declined to rule on the request but retained authority to require GMP to provide specific information or to submit any other specific filing.

On November 22, 2000, the IPPs filed dispositive motions in Docket No. 6270, urging the PSB to declare that it lacks jurisdiction to grant relief sought by the Company's Petition. On January 8, 2001, the Company and the other petitioning utilities filed responses to the IPPs' motions, supporting the PSB's exercise of jurisdiction, as called under the Petition. The DPS also made a filing in support of jurisdiction. On June 1, 2001, the PSB Hearing Officer issued a Proposal for Decision ("PFD") on the PSB's jurisdiction to consider the Petition. The PFD recommended that the PSB find that it has jurisdiction to consider the relief sought under the Petition but that the PSB may be precluded from issuing orders reducing the lengths of a Purchasing Agent contract or requiring buy-outs or buy-downs. Docket participants filed comments on the PFD. On September 18, 2001, the PSB issued an Order regarding jurisdiction in which it adopted the conclusions of the Hearing Officer's PFD and found that it has jurisdiction to consider five of the seven claims outlined in the original Petition.

The IPPs also filed a related proceeding in the Washington County Superior Court contending that the PSB rules pertaining to IPPs, which the utilities have relied upon, in part, in their Petition before the PSB, contains a so-called "scrivener's error." By motion filed in the Superior Court in September 2000, the IPPs sought summary judgement in this action. On January 19, 2001, the Washington County Superior Court dismissed the IPPs' action, which the IPPs appealed to the Vermont Supreme Court. The IPPs also asked the Vermont Supreme Court to stay the proceeding before the PSB pending the outcome of their appeal. By order dated April 5, 2001, the Vermont Supreme Court denied the IPPs' request for a stay.

On March 15, 2001, the IPPs also filed a related complaint before the FERC, requesting that the FERC issue an order preventing the Company and the other Vermont utilities from employing FERC Order No. 888 to require the IPPs, either directly or indirectly, to reserve transmission service and pay transmission charges in connection with their power sales. In principal part the IPPs argue that such reservations and related charges are prohibited under the regulations adopted by the State of Vermont to implement the Public Utilities Regulatory Policies Act of 1978. On April 4, 2001, the Company and other Vermont utilities filed their response arguing that the IPP complaint should be dismissed on procedural grounds and opposing the IPPs' allegations on the merits. By Order dated May 16, 2001, the Commission declined to grant the relief requested and instead found that the complaint was premature in light of the fact that the PSB has yet to rule on the disputed issues in the proceeding open before it to consider the Petition.

In September 2001, the Petitioners and the IPPs agreed to enter into a settlement discussion and on September 28, 2001 filed a Stipulation for Stay requesting that further proceedings in the Docket be stayed to provide the parties an opportunity to engage in settlement negotiations. A similar motion was also filed with the Vermont Supreme Court regarding the appeal on the so-called "scrivener's error" case. On October 18, 2001, the PSB Hearing Officer issued an order granting the Stipulation for Stay and indicated that a status conference would be convened midway through the 90-day period, which was due to expire January 4, 2002. A status conference on the parties' settlement efforts was convened on November 27, 2001.

After several extensions, on January 28, 2002, the Petitioners and the IPPs filed a Memorandum of Understanding with the PSB which, if approved, establishes a comprehensive settlement to the issues in Docket No. 6270. The Memorandum of Understanding would provide:

1. power cost reductions nominally worth approximately $11.0 million to $14.0 million over ten years;
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.

At this time, proceedings are continuing in PSB Docket No. 6270 to consider the Memorandum of Understanding. A status conference on the matter was held in February 2002. A decision in this matter is expected in 2002.

Hydro-Quebec The Company is purchasing varying amounts of power from Hydro-Quebec under the VJO Power Contract through 2016. Related contracts were negotiated between the Company and Hydro-Quebec, which in effect altered the terms and conditions contained in the contract, which reduced the overall power requirements and cost of the original contract.

The average annual amount of capacity that the Company will purchase from January 1, 2002 through October 31, 2012 is 143 mW, with lesser amounts purchased through October 31, 2016. The Company's total commitment to purchase power under these contracts on a nominal basis is approximately $877 million over the contract term. 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.

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 year's 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 also can exercise an option, upon one years written notice, to curtail energy deliveries from an annual load factor of 75% to 50% due to adverse hydraulic conditions in Quebec. This can be exercised five times between November 2000 and October 2015. Additionally, the VJO can elect to change the annual load factor from 75% to between 70% and 80% five times through 2020, while Hydro-Quebec can elect to reduce the load factor to not less than 65% 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 has since elected to push the start of the 65% load factor to November 1, 2002. The Company does not expect this change in load factor to have a significant financial impact.

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, 2001, the Company's obligation is approximately 46% of the total VJO Power Contract through 2016. The projected total VJO contract obligation on a nominal basis over the term of the contract (2020) is approximately $1.9 billion.

During January 1998, a significant ice storm affected parts of New York, New England and the Province of Quebec, Canada. This storm damaged major components of the Hydro-Quebec transmission system over which power is supplied to Vermont under the VJO Power Contract with Hydro-Quebec. This resulted in a 61-day interruption of a significant portion of scheduled contractual energy deliveries into Vermont. The ice storm's effect on Hydro-Quebec's transmission system caused the VJO to examine Hydro-Quebec's overall reliability and ability to deliver energy. On the basis of that examination, the VJO determined that Hydro-Quebec had been and remained unable to make available capacity with the degree of firmness required by the VJO Power Contract. That determination prompted the VJO to initiate an arbitration proceeding. In the arbitration, the VJO was seeking to terminate the contract, to recover damages associated with Hydro-Quebec's failure to comply with the contract, and to recover capacity payments made during the period of non-delivery.

In September 1999, an initial two weeks of hearings were held dealing primarily with issues of contract interpretation. Additional hearings dealing with technical issues were held in the second and third quarters of 2000. On April 17, 2001, the Company received a decision in the arbitration proceeding relating to the failure by Hydro-Quebec to deliver power during the outage in 1998. The decision stated that the long-term power supply contract between Hydro-Quebec and the Vermont utilities remains in effect, that Hydro-Quebec is required to reimburse the Vermont utilities for capacity payments made during the outage for power not delivered and ordered a refund to the VJO, valued at up to approximately $20.0 million plus interest, which amount would be adjusted downward to reflect either actual deliveries by Hydro-Quebec in the first quarter of 1998 or an agreement by the parties.

In accordance with a PSB Accounting Order, the Company deferred legal, consulting and related costs associated with this arbitration of approximately $6.4 million at September 30, 2001. These deferred costs were offset by incremental revenue of $3.8 million, resulting from the implementation of deseasonalized rates on July 1, 2000 through December 31, 2000, as directed by the PSB. As part of the Company's June 26, 2001 rate order, the Company agreed that all amounts collected based on the award issued by the arbitration panel, or any settlement agreement with Hydro-Quebec or any other party related to the Company's VJO contract power supply costs, shall be applied first to reduce the remaining balance of deferred costs related to the ice storm arbitration, with the remaining balance, if any, applied to reduce other regulatory asset accounts as specified by the DPS and approved by the PSB.

On July 19, 2001, Hydro-Quebec and the VJO agreed to a final settlement of the arbitration issues. Under the settlement, the VJO will continue to receive power and energy from Hydro-Quebec under this contract through 2016. As part of the settlement, Hydro-Quebec made a $9.0 million payment to the VJO in July 2001, 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 the deferred costs related to the ice storm arbitration. 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 of the Hydro-Quebec settlement to remaining regulatory assets, which agreement is subject to approval by the PSB. Currently, the remaining $1.6 million balance is included as a deferred credit on the Company's Consolidated Balance Sheet.

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 2001	December 31 2000
Generating plants:						
Wyman #4	Oil	1.78%	1978	11.0	$ 3,347	$ 3,347
Joseph C. McNeil	Various	20.00%	1984	10.6	15,365	15,273
Millstone Unit #3	Nuclear	1.73%	1986	20.0	76,143	75,873
Highgate Transmission Facility		47.35%	1985	N/A	14,086	14,052
					108,941	108,545
Accumulated depreciation					47,049	44,146
					$ 61,892	$ 64,399

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

The Company remained an owner of the Millstone Unit #3 facility when DNC became the lead owner with approximately 93.47% of the plant joint-ownership. As part of the regulatory approvals of the sales to DNC by the joint owners of that plant, DNC has represented to the Nuclear Regulatory Commission ("NRC") and other regulatory bodies, including the Connecticut Department of Public Utility Control, that the Millstone Unit #3 Decommissioning Trust Fund, for its share of the plant, exceeds the NRC minimum calculation required and therefore no further contributions to the fund are required at this time. The Company has agreed with the DPS position in its recent rate case that the DNC representation that contributions currently can cease is appropriate subject to periodic review of both the fund balance and the NRC minimum calculation upon which the DNC bases its assertion of fund adequacy. 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 engaged in various operations and activities which 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.

Company operations occasionally result in unavoidable, inadvertent releases of regulated substances or materials; for example, the rupture of a pole-mounted transformer or a broken hydraulic line. Whenever the Company learns of such a release, the Company responds in a timely fashion and in a manner that complies with all federal and state requirements. Except as discussed in the following paragraphs, the Company is not aware of any instances where it has caused, permitted or suffered a release or spill on or about its properties or otherwise which is likely to result in any material environmental liabilities to the Company.

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 continues to investigate, evaluate, monitor and, where appropriate, remediate contaminated sites related to these past activities. 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. As part of that process, the Company also researches the possibility of insurance coverage that could defray any such remediation expenses.

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. After completing its preliminary investigation, the Company engaged a consultant to assist in evaluating clean-up methodologies and provide cost estimates. Those studies indicated the cost to remediate the site would be approximately $5.0 million. This was charged to expense in the fourth quarter of 1992. 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 April 2000, the Company presented the assessment findings to the States of New Hampshire and Vermont and the Town of Brattleboro. The State of Vermont concluded that additional semi-annual site monitoring is necessary and that the Company must develop a corrective action plan. The State of New Hampshire required additional work to validate certain findings and conclusions made by the Company's consultant after completing its initial investigation in 1999.

In early 2001, the Company submitted a work plan to the State of New Hampshire to address their concerns and 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. In the third quarter of 2001, the Company submitted a corrective action plan to the State of Vermont. 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 is approved. The Company will now proceed with implementation of the corrective action plan, which includes provisions for 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 is partially liable for remediation of this site. PSNH's allegation is 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 already participated in a non-binding mediation to further investigate the terms and conditions surrounding the sale of the plant to PSNH and Twin State's merger into the Company.

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 will be published and submitted to the State of New Hampshire in early 2002. Shortly thereafter, the Company and others will begin evaluating remediation options for the site.

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, or "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 others 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.

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.

As of December 31, 2001, a reserve of $9.2 million has been established representing Management's best estimate of the costs to remediate the sites discussed above.

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 $90.2 million of retained earnings was not subject to dividend restriction at December 31, 2001.

Under the Company's Second Mortgage Indenture, certain additional 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, approximately $19.4 million of retained earnings would not be subject to dividend restrictions at December 31, 2001.

In addition, Catamount and SmartEnergy Water Heating Services, Inc., have 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% 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% 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 and decline from approximately $4.0 million to $3.0 million for each year from 2002 through 2015 and will decline thereafter.

The Company's shares of the net capital cost of these facilities, totaling approximately $14.0 million, are classified in the accompanying Consolidated Balance Sheets as Utility Plant and Capital lease obligations (current and non-current).

Minimum rental commitments of the Company under non-cancelable leases as of December 31, 2001, are considered minimal as the majority of the Company's leases are cancelable after one year from lease inception. Total rental expense entering into the determination of net income, consisting principally of vehicle and equipment rentals, was approximately $4.2 million each year for 1999, 2000 and 2001.

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 effect on the financial position or the result of operations of the Company.

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 ■ RECENT ACCOUNTING PRONOUNCEMENTS

Derivative Instruments: On January 1, 2001, the Company adopted SFAS No. 133 (subsequently amended by SFAS No. 137 and 138), *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"). This Statement, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

The Company has one long-term purchase 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. On April 11, 2001, the PSB approved an Accounting Order that allows the fair valuation adjustment of this contract to be deferred on the balance sheet as either a deferred asset or liability. At December 31, 2001, this derivative had an estimated fair market value of approximately a $1.0 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.

Goodwill and Other Intangible Assets: In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 142, *Goodwill and Other Intangible Assets* ("SFAS No. 142"), effective for fiscal years beginning after December 15, 2001. SFAS No. 142 establishes a new accounting standard for the treatment of goodwill. The new standard continues to require recognition of goodwill as an asset in a business combination but does not permit amortization as is done under current accounting standards. Effective January 1, 2002, SFAS No. 142 requires that goodwill be separately tested for impairment using a fair-value based approach as opposed to the undiscounted cash flow approach used under current accounting standards. If goodwill is found to be impaired, the Company would be required to record a non-cash charge against income, which would be recorded as a cumulative effect of a change in accounting principle. The impairment charge would be equal to the amount by which the carrying amount of the goodwill exceeds its estimated fair value. The Company has no goodwill related to its regulated businesses, however, Catamount has goodwill of approximately $2.0 million related to three of its investments, but does not expect an impairment resulting from the implementation of SFAS No. 142.

Asset Retirement Obligations: In August 2001, the 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 in the period in which it is incurred. The Company has identified potential retirement obligations associated with the decommissioning of its nuclear facilities, but has not yet completed its assessment. This statement is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. The Company has not yet quantified the impacts, if any, of adopting SFAS No. 143 on its financial statements.

Impairment or Disposal of Long-Lived Assets: In October 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144") which replaces SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*. This statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets. Although SFAS No. 144 supercedes SFAS No. 121, it retains the fundamental provisions of SFAS No. 121 regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under SFAS No. 144, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). SFAS No. 144 is effective beginning January 1, 2002 and, generally, is to be applied prospectively. The Company does not expect that SFAS No. 144 will have a significant impact on its financial position or results of operations.

NOTE 15 ■ 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; Catamount Energy Corporation ("Catamount"), which has investments in non-regulated, energy-supply projects in North America and Western Europe; and Eversant Corporation ("Eversant"), which pursues retail alliances to market energy and related products and services, engages in the sale of or rental of electric water heaters to customers in Vermont and New Hampshire and as of December 31, 2001, had a 13.4% ownership interest, on a fully diluted basis, in the Home Services Store ("HSS"), operating nationwide. On October 23, 2001, SmartEnergy Services, Inc. changed its name to Eversant Corporation. CVEC, while managed on an integrated basis with CV, is presented separately because of its separate and distinct regulatory jurisdiction. Other operating segments include a segment below the quantitative threshold for separate disclosure. This operating segment is 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. Certain information for 2000 and 1999 has been restated for the separate reporting of equity income – non-utility affiliates.

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 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 2001, 2000 and 1999 is as follows (dollars in thousands):

	CV VT	CVEC NH	Catamount	Eversant	Other(1)	Reclassification and Consolidating Entries	Consolidated
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 (2)	15,458	475	57	315	3	375	15,933
Regulatory asset write-off (6)	9,000	-	-	-	-	-	9,000
Reversal of estimated loss on power contracts (3)	2,934	-	-	-	-	-	2,934
Asset impairment charges (5)	-	-	8,905	-	-	-	8,905
Investment write-down (5)	-	-	-	1,963	-	-	1,963
Taxes on income	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 (4)	2,669	-	-	-	-	-	2,669
Equity income - non-utility affiliates	-	-	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, at equity	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 (2)	21,646	495	63	277	3	343	22,141
Reversal of estimated loss on power contracts (3)	-	1,202	-	-	-	-	1,202
Purchased power disallowance (3)	(2,934)	-	-	-	-	-	(2,934)
Reversal of purchased power disallowance (3)	11,436	-	-	-	-	-	11,436
Taxes on income	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 (4)	3,268	-	-	-	-	-	3,268
Equity income - non-utility affiliates	-	-	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, at equity	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
1999							
Revenues from external customers	$399,268	$20,551	$ 1,316	$ 7,306	$ 7	$ 8,633	$419,815
Intersegment revenues	11,938	-	-	-	-	11,938	-
Depreciation and other (2)	12,221	463	38	347	3	388	12,684
Reversal of estimated loss on power contracts (3)	-	1,586	-	-	-	-	1,586
Estimated loss on power contracts (3)	-	(1,202)	-	-	-	-	(1,202)
Purchased power disallowance (3)	(2,859)	-	-	-	-	-	(2,859)
Reversal of purchased power disallowance (3)	7,361	-	-	-	-	-	7,361
Taxes on income	10,408	49	1,382	(1,960)	24	(457)	10,360
Operating income (loss)	24,146	491	(2,871)	2,453	(23)	(455)	24,651
Equity income - utility affiliates (4)	2,844	-	-	-	-	-	2,844
Equity income - non-utility affiliates	-	-	4,471	(5,266)	-	(795)	-
Other income (expenses), net	2,145	5	563	(22)	69	1,513	1,247
Interest expense, net	11,880	393	101	39	-	255	12,158
Net income (loss)	17,254	102	2,061	(2,873)	40	-	16,584
Investments in affiliates, at equity	25,501	-	-	-	-	-	25,501
Total assets	504,120	12,670	46,798	4,526	4,407	8,562	563,959
Capital expenditures	12,723	393	115	-	-	-	13,231

(1) Includes a segment below the quantitative threshold.
(2) 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 Statement of Income.
(3) Included in Purchased power in the accompanying Consolidated Statement of Income.
(4) See Note 2 herein for CV's investments in affiliates.
(5) See Note 3 herein for CV's investment in non-utility affiliates.
(6) See Note 12 herein for CV's retail rates.

NOTE 16 ■ 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. Variations in Operating revenues and income between quarters reflect the seasonal nature of the Company's business (dollars in thousands, except per share amounts):

	Quarter Ended				12 Months
	March	June	September	December	Ended
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	$ 0.30	$ (0.01)	$ 0.27	$ (0.50)	$ 0.06
2000					
Operating revenues	$99,949	$73,867	$73,947	$86,163	$333,926
Operating income	$12,564	$ 2,077	$ 2,953	$ 6,985	$ 24,579
Net income	$ 7,959	$ 274	$ 4,802	$ 5,008	$ 18,043
Earnings per share of common stock	$ 0.66	$ (0.01)	$ 0.38	$ 0.40	$ 1.42

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, NHPUC 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.

Arthur Andersen LLP, independent public accountants, have 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

John J. Holtman

JOHN J. HOLTMAN
Vice President, Controller and
Principal Accounting Officer

	'01	'00	'99	'98	'97	'96	'91
COMMON STOCK DATA							
Earnings per share	$.06	$1.42	$1.28	$ .18	$1.25	$1.51	$1.65
Earnings per share before extraordinary items	$.08	$1.42	$1.28	$ .18	$1.32	$1.51	$1.65
Dividend paid per share	$.88	$ .88	$ .88	$ .88	$ .88	$ .84	$1.39
Book value per share (year-end)	$15.81	$16.57	$16.05	$15.63	$16.38	$16.19	$14.03
Consolidated return on average equity	0.4%	8.6%	7.9%	1.1%	7.5%	9.4%	11.8%
Dividend payout ratio	1,467%	62%	69%	489%	70%	56%	84%
Earnings (000's)	$711	$16,264	$14,722	$2,038	$14,312	$17,414	$17,514
Earnings (000's) before extraordinary items	$893	$16,264	$14,722	$2,038	$15,123	$17,414	$17,514
MARKET PRICE RANGE PER SHARE							
High	19.625	13.0000	14.4375	15.4375	15.3125	15.125	22.875
Low	11.625	9.7500	9.5625	9.7500	10.3750	12.000	17.000
Year-end	16.700	12.1875	10.6250	10.3750	15.2500	12.000	22.750
Market price as a percent of book value (year-end)	106%	74%	66%	66%	93%	74%	162%
Price earnings ratio	278.3	8.6	8.3	57.6	12.2	7.9	13.8
Average number of shares outstanding	11,551,042	11,488,351	11,463,197	11,439,688	11,458,735	11,543,998	10,614,642
Total shares outstanding	11,610,683	11,507,980	11,466,805	11,461,131	11,423,401	11,519,748	10,808,463
CAPITALIZATION DATA (000's)							
Common stock equity	$183,514	$190,697	$184,021	$179,182	$187,123	$186,469	$151,680
Non-redeemable preferred	8,054	8,054	8,054	8,054	8,054	8,054	15,054
Redeemable preferred (incl. current portion)	16,000	16,000	17,000	18,000	19,000	20,000	20,000
Long-term debt (incl. current portion)	166,996	157,180	171,939	96,850	117,370	120,389	136,940
Long-term lease (incl. current portion)	13,986	15,067	16,148	17,229	18,311	19,392	23,729
Short-term debt	-	-	-	37,000	12,650	5,750	-
Total capitalization	$388,550	$386,998	$397,162	$356,315	$362,508	$360,054	$347,403
RATIOS							
Common Stock equity	47.2%	49.3%	46.3%	50.3%	51.6%	51.8%	43.7%
Non-redeemable preferred	2.1%	2.1%	2.0%	2.3%	2.2%	2.2%	4.3%
Redeemable preferred (incl. current portion)	4.1%	4.1%	4.3%	5.0%	5.2%	5.6%	5.8%
Long-term debt (incl. current portion)	43.0%	40.6%	43.3%	27.2%	32.4%	33.4%	39.4%
Long-term lease (incl. current portion)	3.6%	3.9%	4.1%	4.8%	5.1%	5.4%	6.8%
Short-term Debt	-	-	-	10.4%	3.5%	1.6%	-
OTHER FINANCIAL DATA							
Net utility plant (000's)	$308,629	$310,976	$314,732	$319,947	$321,646	$324,941	$311,978
Total assets (000's)	$521,674	$539,838	$563,959	$530,282	$531,940	$502,968	$430,748
Construction & Plant Expenditures/ C&LM (incl. AFDC)(000's)	$17,057	$16,104	$15,671	$18,254	$15,678	$20,541	$20,896
Net cash provided by operating activities (000's)	$30,216	$60,867	$31,232	$21,743	$41,974	$43,007	$36,415
Times interest earned							
Before income taxes	1.8x	3.1x	3.2x	.5x	3.6x	3.9x	2.8x
After income taxes	1.2x	2.3x	2.4x	1.4x	2.7x	2.9x	2.4x
Times interest and preferred dividend earned							
After income taxes	1.1x	2.0x	2.1x	1.2x	2.2x	2.4x	2.2x
Embedded cost of long-term debt (year-end)	7.2%	7.8%	7.8%	7.5%	7.5%	7.6%	9.1%
Embedded cost of preferred stock (year-end)	7.0%	7.1%	7.1%	7.2%	7.2%	7.2%	7.6%

	'01	'00	'99	'98	'97	'96	'91
OPERATING DATA							
Electric Revenues (000's)							
Residential	$124,844	$124,237	$123,302	$115,911	$116,314	$108,603	$92,409
Commercial	110,482	106,089	109,440	103,221	104,460	98,890	81,393
Industrial	35,888	38,521	36,823	33,617	34,206	32,399	29,698
Other	1,787	1,779	1,787	1,943	1,937	1,856	1,603
Total Retail	$273,001	$270,626	$271,352	$254,692	$256,917	$241,748	$205,103
Wholesale							
Firm	139	142	160	94	46	81	3,793
Entitlement	7,303	10,763	20,875	19,370	18,925	24,781	19,630
Other	16,153	20,534	22,121	15,595	22,265	18,705	10,039
Alliance	-	22,192	100,116	11,266	-	-	-
Other revenues	5,880	9,669	5,191	2,818	6,579	5,486	(4,058)
Total	$302,476	$333,926	$419,815	$303,835	$304,732	$290,801	$234,507
Total (excluding entitlement, other and Alliance)	$279,020	$280,437	$276,703	$257,604	$263,542	$247,315	$204,838
Annual percentage change:							
Retail	.9%	(.3)%	6.5%	(.9)%	6.3%	4.8%	3.6%
Total (excluding entitlement, other and Alliance)	(.5)%	1.3%	7.4%	(2.3)%	6.6%	5.1%	(.6)%
ELECTRIC MWH SALES							
Residential	952,509	963,615	948,756	930,666	945,199	957,733	946,799
Commercial	933,928	933,851	943,141	937,547	916,311	900,590	825,429
Industrial	431,371	465,418	442,308	418,778	427,764	401,781	403,200
Other	6,291	6,280	6,235	7,123	7,138	7,229	8,076
Retail	2,324,099	2,369,164	2,340,440	2,294,114	2,296,412	2,267,333	2,183,504
Wholesale							
Firm	1,927	2,830	2,349	2,284	1,051	1,717	85,200
Entitlement	165,184	299,326	356,197	319,703	378,273	470,760	553,466
Other	406,694	573,055	869,857	651,235	827,818	770,542	352,721
Alliance	-	611,225	2,986,682	357,400	-	-	-
Total	2,897,904	3,855,600	6,555,525	3,624,736	3,503,554	3,510,352	3,174,891
Total (excluding entitlement, other and Alliance)	2,326,026	2,371,994	2,342,789	2,296,398	2,297,463	2,269,050	2,268,704
Annual percentage change							
Retail	(1.9)%	1.2%	2.0%	(.1)%	1.3%	1.5%	2.5%
Total (excluding entitlement, other and Alliance)	(1.9)%	1.2%	2.0%	-	1.3%	1.3%	1.4%
CUSTOMERS (end of year)							
Residential	133,368	131,892	131,621	130,535	129,657	129,343	124,468
Commercial	20,671	19,812	19,445	19,172	19,494	18,428	17,253
Industrial	41	41	42	38	38	36	43
Other	189	188	184	187	186	186	191
Wholesale	5	10	32	29	14	21	17
Total customers	154,274	151,943	151,324	149,961	149,389	148,014	141,972
Annual percentage change	1.5%	.4%	.9%	.4%	.9%	1.9%	2.9%
Average KWH use per residential customer	7,111	7,239	7,184	7,082	7,226	7,345	7,647
Average revenue per residential customer	$932.08	$933.34	$933.68	$882.04	$889.20	$832.95	$746.32
Average revenue per KWH (cents)							
Residential	13.11	12.89	13.00	12.45	12.31	11.34	9.76
Commercial	11.83	11.36	11.60	11.01	11.40	10.98	9.86
Industrial	8.32	8.28	8.33	8.03	8.00	8.06	7.37
FUEL SOURCES							
Nuclear	47.7%	41.1%	37.3%	38.5%	36.0%	37.8%	45.0%
Hydro	39.9%	34.4%	40.9%	38.5%	38.2%	38.0%	30.2%
Coal	-	-	-	2.1%	9.4%	7.8%	8.6%
Oil	2.6%	2.7%	1.4%	3.7%	1.8%	1.5%	11.7%
Wood/Other	9.8%	21.8%	20.4%	17.2%	14.6%	14.9%	4.5%
POWER SOURCES							
Nuclear generating companies	43.1%	43.4%	33.5%	36.8%	35.7%	36.6%	43.5%
Canadian imports	35.2%	34.2%	35.5%	31.3%	32.3%	29.8%	21.9%
PSNH-coal	-	-	-	2.1%	9.4%	7.8%	8.0%
Company-owned hydro	4.2%	5.6%	4.9%	6.5%	5.2%	6.0%	5.6%
NYPA-hydro	-	-	-	-	-	-	2.7%
Joint-ownership units	6.1%	7.6%	5.9%	3.2%	1.2%	2.0%	3.0%
Independent Power Producers	5.4%	5.8%	5.1%	6.1%	5.6%	5.9%	3.3%
Other	6.0%	3.4%	15.1%	14.0%	10.6%	11.9%	12.0%
System capability (MW)(peak)	460	446	543	565	549	508	483
Reserve margin (peak)	12%	28%	29%	34%	37%	24%	16%
System peak (MW)	412	430	421	421	400	410	418
Load factor	69.5%	67.4%	69.2%	67.3%	71.0%	68.3%	65.8%
Number of employees - regulated	543	525	518	514	596	624	750
Number of employees - non-regulated	29	30	24	18	14	13	5
Number of registered shareholders	10,073	10,135	10,862	11,905	13,686	14,740	14,900

COMMON STOCK PRICES AND DIVIDENDS

	High	Low	Dividends Per Share
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
2000			
1st quarter	$11.5625	$9.8125	$.22
2nd quarter	11.25	10.125	.22
3rd quarter	13.00	9.9375	.22
4th quarter	12.4375	9.75	.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
Attn. DRP Department
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 7, 2002, 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, DRP Department 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 corporation represent taxable income to shareholders for federal income tax purposes. No portion of the 2001 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 2002.

	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:

Alf Strom-Olsen
Director of Treasury Services
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

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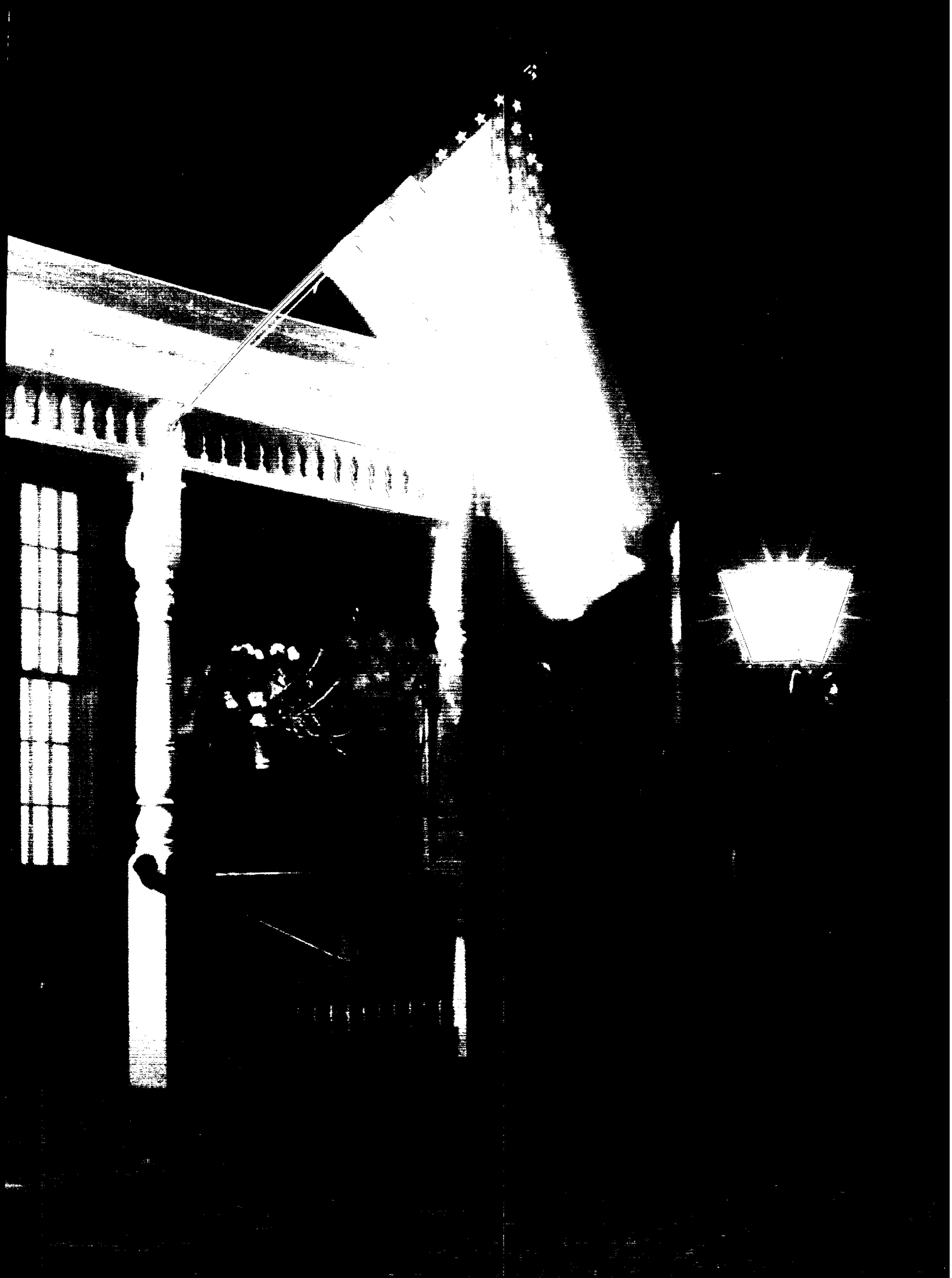

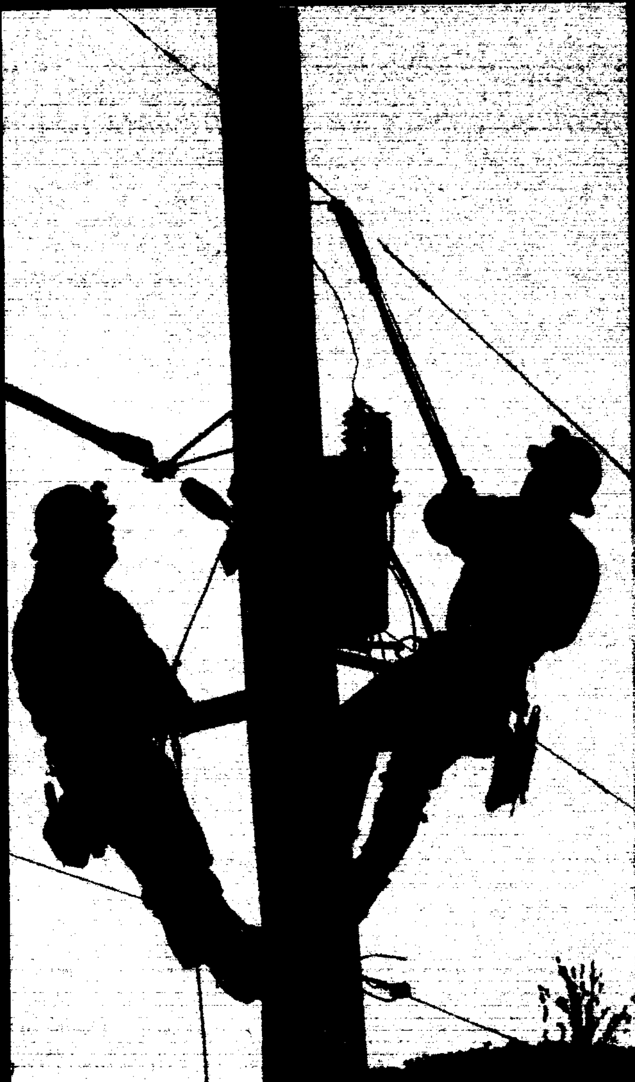

Central Vermont Public Service

77 GROVE STREET
RUTLAND, VERMONT 05701
1-800-649-CVPS

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