UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 1-8222

Central Vermont Public Service Corporation
(Exact name of registrant as specified in its charter)

Vermont **(State or other jurisdiction of incorporation or organization)**	03-0111290 **(IRS Employer Identification No.)**
77 Grove Street, Rutland, Vermont **(Address of principal executive offices)**	05701 **(Zip Code)**

Registrant's telephone number, including area code (800) 649-2877

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock $6 Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes **[ ]** No **[X]**

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes **[ ]** No **[X]**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes **[X]** No **[ ]**

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. **[ ]**

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer, "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer **[ ]** Accelerated filer **[X]**

Non-accelerated filer **[ ]** Smaller Reporting Company **[ ]**
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes **[ ]** No **[X]**

The aggregate market value of voting and non-voting common equity held by non affiliates of the registrant as of June 30, 2007 (2nd quarter) was approximately $268,817,975 (based on the $37.68 per share closing price of the Company's Common Stock, $6 Par Value, as reported on the New York Stock Exchange Market on June 29, 2007). In determining who are affiliates of the Company for purposes of computation, it is assumed that directors, officers, and other persons who held on December 31, 2007, more than 5 percent of the issued and outstanding Common Stock of the Company are "affiliates" of the Company. The characterization of such directors, officers, and other persons as affiliates is for the purposes of this computation only and should not be construed as a determination or admission for any other purpose.

On February 29, 2008 there were outstanding 10,274,607 shares of voting Common Stock, $6 Par Value.

DOCUMENTS INCORPORATED BY REFERENCE

The Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 6, 2008 to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Act of 1934, is incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
FORM 10-K - 2007

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Cautionary Statement Regarding Forward-Looking Information

Statements contained in this report that are not historical fact are forward-looking statements within the meaning of the 'safe-harbor' provisions of the Private Securities Litigation Reform Act of 1995. Whenever used in this report, the words "estimate," "expect," "believe," or similar expressions are intended to identify such forward-looking statements. Forward-looking statements 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 upon, among other things:

- the actions of regulatory bodies with respect to allowed rates of return, continued recovery of regulatory assets and proposed alternative regulations;
- performance and continued operation of the Vermont Yankee nuclear power plant;
- effects of and changes in weather and economic conditions;
- volatility in wholesale power markets;
- ability to maintain or improve our current credit ratings;
- the operations of ISO-New England;
- changes in the cost or availability of capital;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- capital market conditions, including price risk due to marketable securities held as investments in trust for nuclear decommissioning, pension and postretirement medical plans;
- changes in the levels and timing of capital expenditures, including our discretionary future investments in Transco;
- our ability to replace or renegotiate our long-term power supply contracts;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel;
- and other presently unknown or unforeseen factors.

We cannot predict the outcome of any of these matters; accordingly, there can be no assurance as to actual results. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Item 1. Business

(a) General Description of Business

Central Vermont Public Service Corporation (the "company" or "we" or "our" or "us"), incorporated under the laws of Vermont on August 20, 1929, is engaged in the purchase, production, transmission, distribution and sale of electricity. We are the largest electric utility in Vermont, serving about 158,000 retail customers in nearly two-thirds of the towns, villages and cities in Vermont. Our wholly owned subsidiaries include:

- Custom Investment Corporation ("Custom"), which was formed for the purpose of holding passive investments, including the stock of our subsidiaries that invest in regulated business opportunities. On October 13, 2003, we transferred our shares of Vermont Yankee Nuclear Power Corporation ("VYNPC") to Custom. The transfer to Custom does not affect our rights and obligations related to VYNPC.
- C.V. Realty, Inc., a real estate company that owns, buys, sells and leases real and personal property and interests therein related to the utility business.
- CVPSC - East Barnet Hydroelectric, Inc. was created for the purpose of financing and constructing a hydroelectric facility in Vermont, and became operational September 1, 1984. We have leased and operated it since the in-service date.
- Catamount Resources Corporation ("CRC") formed for the purpose of holding our subsidiaries that invest in unregulated business opportunities. CRC has a wholly owned subsidiary, Eversant Corporation, which engages in the sale or rental of electric water heaters in Vermont and New Hampshire through a wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. CRC had a wholly owned subsidiary, Catamount Energy Corporation ("Catamount"), which invested primarily in wind energy in the United States and the United Kingdom. In December 2005, CRC completed the sale of all of its interest in Catamount to CEC Wind Acquisition, LLC, a Delaware limited liability company established by Diamond Castle Holdings.

- In 2007, we dissolved our wholly owned subsidiary Connecticut Valley Electric Company, Inc. ("Connecticut Valley"), which had been incorporated under the laws of New Hampshire on December 9, 1948. Connecticut Valley distributed and sold electricity in parts of New Hampshire bordering the Connecticut River, until January 1, 2004 when it completed the sale of substantially all of its plant assets and its franchise to Public Service Company of New Hampshire.
- Our equity ownership interests as of December 31, 2007 are summarized below. These are also described in more detail in Part II, Item 8, Note 3 - Investments in Affiliates.
- We own 58.85 percent of the common stock of VYNPC, which was initially formed by a group of New England utilities to build and operate a nuclear-powered generating plant in Vernon, Vermont. On July 31, 2002, VYNPC sold the plant to Entergy Nuclear Vermont Yankee, LLC ("ENVY"). The sale agreement included a purchased power contract ("PPA") between VYNPC and ENVY. Under the PPA, VYNPC pays ENVY for generation at fixed rates, and in turn, bills the PPA charges from ENVY with certain residual costs of service through a FERC tariff to us and the other VYNPC sponsors.
- We own 47.05 percent of the common stock and 48.03 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"), which owned the high-voltage transmission system in Vermont. In June 2006, VELCO transferred substantially all of its business operations and assets to Vermont Transco LLC ("Transco"). VELCO has a 12.52 percent equity interest in Transco and manages the operations of Transco under a Management Services Agreement. VELCO's wholly owned subsidiary, Vermont Electric Transmission Company, Inc. was formed to finance, construct and operate the Vermont portion of the 450 kV DC transmission line connecting the Province of Quebec with Vermont and New England.
- We own 39.79 percent of Class A Units of Transco, which was formed by VELCO and its owners in June 2006. Transco owns and operates the high-voltage transmission system in Vermont. Our total direct and indirect interest in Transco is 45.68 percent.
- We own 2 percent of the outstanding common stock of Maine Yankee Atomic Power Company ("Maine Yankee"), 2 percent of the outstanding common stock of Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and 3.5 percent of the outstanding common stock of Yankee Atomic Electric Company ("Yankee Atomic"). All of the plants have been permanently shut down and have completed decommissioning.

We also own small generating facilities and have joint ownership interests in certain generating facilities. These are described in Sources and Availability of Power Supply below.

(b) Financial Information about Industry Segments

Our two principal operating segments are the regulated utility business and the aggregate of the other companies. See Part II Item 8, Note 17 - Segment Reporting for financial information regarding those operating segments.

(c) Narrative Description of Business

Principal Products and Services

Our operating revenues consist primarily of retail and resale sales. Retail sales are comprised of sales to a diversified customer mix including residential, commercial and industrial customers. Sales to the five largest retail customers receiving electric service accounted for about 6 percent of our annual retail electric revenues for 2007, 2006 and 2005. Resale sales are comprised of long-term sales to third parties in New England, sales in the energy markets administered by ISO-New England and short-term system capacity sales. Our operating revenues and energy sales as of December 31 consisted of the following:

	Revenue			**mWh Sales**		
	2007	2006	2005	**2007**	2006	2005
Retail Sales:						
Residential	**41%**	38%	41%	**33%**	29%	33%
Commercial	**33%**	32%	33%	**29%**	27%	31%
Industrial and other	**11%**	12%	12%	**14%**	13%	14%
Resale Sales	**12%**	16%	13%	**24%**	31%	22%
Customer refund	**-**	-	(2%)	**-**	-	-
Other operating revenue	**3%**	2%	3%	**-**	-	-

Retail Rates Our retail rates are set by the Vermont Public Service Board ("PSB") after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). While our retail rates do not include fuel or power cost adjustment mechanisms, the PSB has previously approved the deferral of extraordinary costs incurred that might normally be expensed by unregulated businesses in order to match these expenses with future revenues. Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital.

Our retail rates at December 31, 2007 were based on a December 7, 2006 PSB Order that provided for, among other things, a 4.07 percent rate increase effective January 1, 2007, and an allowed rate of return on common equity of 10.75 percent capped until our next rate proceeding.
On May 15, 2007, we filed a request for a retail rate increase of 4.46 percent, or $12.4 million in annual revenues, based on the 2006 calendar year. On November 21, 2007, we reached a settlement with the DPS in the case, agreeing to a 2.3 percent rate increase, or additional revenue of $6.4 million on an annual basis, effective with bills rendered on or after February 1, 2008. The agreement allows us a rate of return on common equity of 10.71 percent, capped until our next rate proceeding or approval of an alternative regulation plan. On January 31, 2008, the PSB issued an Order approving the settlement agreement with the rate increase effective February 1, 2008.

Wholesale Rates We provide wholesale transmission service to nine network customers and six point-to-point customers under ISO-New England FERC Electric Tariff No. 3, Section II - Open Access Transmission Tariff (Schedules 21-CV and 20A-CV). We also provide wholesale transmission service to one network customer under a FERC rate schedule. We maintain an OASIS site for transmission on the ISO-New England web page.

Sources and Availability of Power Supply
For the year ended December 31, 2007 our energy generation and purchased power required to serve retail and firm wholesale customers was 2,487,279 mWh. The maximum one-hour integrated demand during that period was 420.6 MW and occurred on August 3, 2007. For 2006, our energy generation and purchased power required to serve retail and firm wholesale customers was 2,461,444 mWh. The maximum one-hour integrated demand was 437.6 MW and occurred on August 2, 2006. The sources of energy and capacity available to us for the year ended December 31, 2007 are as follows:

	Net Effective Capability 12 Month Average	Generated and Purchased	
	MW	mWh	Percent
Wholly Owned Plants:			
Hydro	41.1	181,360	5.8
Diesel and Gas Turbine	25.9	637	-
Jointly Owned Plants:			
Millstone #3	19.9	150,525	4.8
Wyman #4	10.7	5,470	0.2
McNeil	10.7	56,597	1.8
Long-Term Purchases:			
VYNPC	179.6	1,361,754	43.2
Hydro-Quebec	143.2	998,411	31.7
Independent power producers	34.6	176,169	5.5
Other Purchases:			
System and other purchases	0.4	128,269	4.1
NEPOOL (ISO-New England)	-	90,917	2.9
Total	466.1	3,150,109	100.0

Wholly Owned Plants: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of about 74.2 MW. We operate all of these plants, which include: 1) 20 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.3 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 45.3 MW; 2) two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW; and 3) one diesel peaking unit with a nameplate capacity of 2.4 MW. At December 31, 2007 the diesel plant was in deactivated status though its capacity is included in the above totals.

Jointly Owned Plants: We have joint-ownership interests in generating and transmission facilities. We are responsible for our share of the operating expenses of these facilities. Our interests in these facilities for the year ended December 31 follows (dollars in thousands):

	Fuel Type	Ownership	In-Service Date	MW Entitlement	December 31 2007	December 31 2006
Wyman #4	Oil	1.7769%	1978	10.8	**$3,504**	$3,422
Joseph C. McNeil	Various	20.0000%	1984	10.8	**15,587**	15,555
Millstone Unit #3	Nuclear	1.7303%	1986	20.0	**77,349**	77,162
Highgate Transmission Facility		47.5200%	1985	N/A	**14,390**	14,357
					110,830	110,496
Less accumulated depreciation					**62,233**	60,986
					$48,597	$49,510

As shown in the sources and availability of power supply table above, we receive our share of output and capacity from these facilities. Millstone Unit #3 is a 1,155-MW nuclear generating facility, Wyman #4 is a 609-MW generating facility and Joseph C. McNeil is a 54-MW generating facility. The Highgate Converter, a 225-MW facility, is directly connected to the Hydro-Quebec System to the north and to the Transco system for delivery of power to Vermont utilities. This facility can deliver power in either direction, but predominantly delivers power from Hydro-Quebec to Vermont.

Major Long-Term Purchases

Vermont Yankee: We purchase our entitlement share of Vermont Yankee plant output from VYNPC under the PPA between VYNPC and ENVY. The PPA extends through the plant's current license life, which expires in 2012. On June 8, 2006, the plant received a new output rating of approximately 620 MW, a 20 percent increase in plant capacity. Our entitlement of total plant output was reduced from 35 percent to 29 percent in September 2006 due to the uprate, but our share of plant output is similar to the amount received before the uprate process began. Prices under the PPA range from $39 to $45 per mWh. The PPA contains a provision known as the "low market adjuster" that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price.

ENVY has no obligation to supply energy to VYNPC over the amount the plant is producing, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. We are responsible for purchasing replacement energy at these times. The next refueling outage is scheduled for late 2008. We have entered into a forward purchase contract for replacement energy during the scheduled outage. We also purchased forced outage insurance to cover additional costs, if any, of obtaining replacement power from other sources if Vermont Yankee experiences unplanned outages between January 1 and December 31, 2008.

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose about 50 percent of our committed energy supply and would have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB will allow timely and full recovery of increased costs related to any such shutdown. An early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion.

Hydro-Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO is a group of Vermont electric companies, municipal utilities and cooperatives of which we are a member. The VJO Power Contract has been in place since 1987 and purchases under the contract began in 1990. Subsequently, we negotiated related contracts with Hydro-Quebec that altered the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO contract runs through 2020, but our purchases under the contract end in 2016. As of December 31, 2007, our obligation was about 47 percent of the total VJO Power Contract through 2016. The average annual amount of capacity that we will purchase from January 1, 2008 through October 31, 2012 is about 144.8 MW, with lesser amounts purchased through October 31, 2016.

In the early phase of the VJO Power Contract, two sellback contracts were negotiated, the first delaying the purchase of 25 MW of capacity and associated energy, the second reducing the net purchase of Hydro-Quebec power through 1996. In 1994, we negotiated a third sellback arrangement whereby we received a reduction in capacity costs from 1995 to 1999. In exchange, Hydro-Quebec obtained two options. The first gives Hydro-Quebec the right, upon four years' written notice, to reduce capacity deliveries by 50 MW, including the use of a like amount of our Phase I/II transmission facility rights. The second gives Hydro-Quebec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Quebec. This second option can be exercised five times through October 2015. Hydro-Quebec has not yet exercised these options.

Under the VJO Power Contract, the VJO had elections to change the annual load factor from 75 percent to between 70 and 80 percent five times through 2020, while Hydro-Quebec had elections to reduce the load factor to not less than 65 percent three times during the same period. Hydro-Quebec and the VJO have used all of their elections. Based on elections made by the VJO in 2005 and 2006, purchases under the VJO Power Contract were at an 80 percent load factor for the contract years beginning November 1, 2005 and 2006. As of November 1, 2007, the annual load factor is 75 percent for the remainder of the contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described above. We, Green Mountain Power, the Vermont Public Power Supply Authority and HQ-Production are using a steering committee structure to develop background materials, terms and supporting actions needed in negotiations for future power purchases from Hydro-Quebec. We believe there is a high probability that we will have a new contract with Hydro-Quebec, and we have agreed to target completion of proposed draft terms by the end of 2008, with a proposed contract for review by the PSB in 2009. We cannot predict whether a contract will ultimately be approved or, if approved, the quantities of power to be purchased or the price terms of any purchases.

Independent Power Producers: We purchase power from several Independent Power Producers ("IPPs") who own qualifying facilities under the Public Utilities Regulatory Policies Act of 1978. These facilities primarily use water and biomass as fuel. Most of the power comes through a state-appointed purchasing agent that assigns power to all Vermont utilities under PSB rules.

Other Purchases

System and Other Purchases, including ISO-New England: We participate in the New England regional wholesale electric power markets operated by ISO-New England Inc., the regional bulk power transmission organization established to assure reliable and economical power supply in New England, which is governed by the Federal Energy Regulatory Commission ("FERC"). We also engage in short-term purchases with other third parties, primarily in New England, to minimize net power costs and risks to our customers. We enter into forward purchase contracts when additional supply is needed and enter into forward sale contracts when we forecast excess supply. On an hourly basis, power is sold or bought through ISO-New England's settlement process to balance our resource output and load requirements.

See Part II, Item 7, Power Supply Matters and Item 8, Note 16 - Commitments and Contingencies for additional information related to our power supply and related long-term power contracts.

Franchise

Pursuant to Vermont statute (30 V.S.A. Section 249), the PSB has established the service area in which we currently operate. Under 30 V.S.A. Section 251(b) no other company is legally entitled to serve any retail customers in our established service area except as described below.

An amendment to 30 V.S.A. Section 212(a) enacted May 28, 1987 authorizes the DPS to purchase and distribute power at retail to all consumers of electricity in Vermont, subject to certain preconditions specified in new sections 212(b) and 212(c). Section 212(b) provides that a review board, consisting of the governor and certain other designated legislative officers, review and approve any retail proposal by the DPS if the review board is satisfied that the benefits outweigh any potential risk to the state. However, the DPS may proceed to file the retail proposal with the PSB either upon approval by the review board or failure of the review board to act within 60 days of the submission. Section 212(c) provides that the DPS shall not enter into any retail sales arrangement before the PSB determines that it is appropriate. The PSB assesses the following factors in reaching its conclusion: 1) the need for the sale; 2) the rates are just and reasonable; 3) the sale will result in economic benefit; 4) the sale will not adversely affect system stability and reliability; and 5) the sale will be in the best interest of ratepayers.

Section 212(d) provides that upon PSB approval of a DPS retail sales request, Vermont utilities shall make arrangements for distributing such electricity on terms and conditions that are negotiated. Failing such negotiation, the PSB is directed to determine such terms as will compensate the utility for all costs reasonably and necessarily incurred to provide such arrangements. Such sales have not been made in our service area since 1993.

In addition, Chapter 79 of Title 30 authorizes municipalities to acquire the electric distribution facilities located within their boundaries. The exercise of such authority is conditioned upon an affirmative three-fifths vote of the legal voters in an election and upon payment of just compensation including severance damages. Just compensation is determined either by negotiation between the municipality and the utility or by the PSB after a hearing, if the parties fail to reach an agreement. If either party is dissatisfied, the statute allows them to appeal the PSB's determination to the Vermont Supreme Court. Once the price is determined, whether by agreement of the parties or by the PSB, a second affirmative three-fifths vote of the legal voters is required.

There have been two instances where Chapter 79 of Title 30 has been invoked. In one instance, the Town of Springfield acted to acquire our distribution facilities in that community pursuant to a vote in 1977; that action was discontinued in 1985. The other instance, which occurred in 2002, involved the Town of Rockingham, which voted to pursue purchase of our distribution facilities, Green Mountain Power's distribution facilities, and another party's hydroelectric facility located in Bellows Falls. We refused to voluntarily sell our distribution facilities. In November 2003, we were notified that Rockingham intended to obtain our facilities by eminent domain under Title 24 V.S.A. Section 2805. We opposed this action as being contrary to Title 30, and in December 2003 obtained a permanent injunction from the Superior Court prohibiting Rockingham from pursuing this course of action. If Rockingham decides to continue this action in the future, it must proceed with the PSB under Title 30. After its option to purchase the Bellows Falls hydroelectric facility expired in 2005, Rockingham discontinued its efforts to acquire our distribution facilities.

Regulation

State Commissions: As described above we are subject to the regulatory authority of the PSB with respect to rates and terms of service. Along with VELCO and Transco, we are subject to PSB jurisdiction related to securities issuances, planning and construction of major generation and transmission facilities and various other matters. Additionally, the Maine Public Utilities Commission exercises limited jurisdiction over us based on our joint-ownership interest as a tenant-in-common of Wyman #4, and the Connecticut Department of Public Utility Control has similar jurisdiction based on our interest in Millstone Unit #3.

Federal Power Act: Certain phases of our business and that of Transco, including certain rates, are subject to the FERC. We are a licensee of hydroelectric developments under Part I of the Federal Power Act, and along with Transco, we are interstate public utilities under Parts II and III, as amended and supplemented by the National Energy Act. We are in the process of licensing two separate hydro-projects under the Federal Power Act. These projects represent about 4.1 MW, or 9 percent of our hydroelectric nameplate capacity. We obtained exemptions from licensing for the Bradford and East Barnet projects.

Federal Energy Policy Act of 2005: The Federal Energy Policy Act of 2005 includes numerous provisions meant to increase domestic gas and oil supplies, improve energy system reliability, build new nuclear power plants, and expand renewable energy sources. It also repealed the Public Utility Holding Company Act of 1935, effective February 2006. By reason of our ownership of utility subsidiaries, we are a holding company, as defined in this act. We have received a blanket exemption from the FERC to acquire securities of Transco, which previously required FERC approval.

Nuclear Regulatory Commission ("NRC"): The nuclear generating facilities in which we have an interest are subject to extensive regulation by the NRC. The NRC is empowered to regulate siting, construction and operation of nuclear reactors with respect to public health, safety, environmental and antitrust matters. Under its continuing jurisdiction, the NRC may require modification of units for which operating licenses have already been issued, or impose new conditions on such licenses, or require that the operation of a unit cease or that the level of operation of a unit be temporarily or permanently reduced.

Competitive Conditions

Competition currently takes several forms. At the wholesale level, New England has implemented its version of FERC's "standard market design" ("SMD"), which is a detailed competitive market framework that has resulted in bid-based competition of power suppliers rather than prices set under cost-of-service regulation. Similar versions of SMD have been implemented in New York and a large abutting multi-state region referred to as PJM. At the retail level, customers have long had energy options. Another competitive threat is the potential for customers to form municipally owned utilities in our service territory.

Competition in the energy services market exists between electricity and fossil fuels. In the residential and small commercial sectors, this competition is primarily for electric space and water heating from propane and oil dealers. Competitive issues are price, service, convenience, cleanliness, automatic delivery and safety.

In the large commercial and industrial sectors, cogeneration and self-generation are the major competitive threats to network electric sales. Competitive risks in these market segments are primarily related to seasonal, one-shift milling operations that can tolerate periodic power outages common to such forms of cogeneration or self-generation, and for industrial or institutional customers with steady heat loads where the generator's waste heat can be used in their manufacturing or space conditioning processes. Competitive advantages for electricity in those segments are: cost stability; convenience; cost of back-up power sources or alternatively, reliability; space requirements; noise problems; air emission and site permit issues; and maintenance requirements. However, there may be some circumstances where cogeneration could provide benefits to us in constrained areas of our system.

Environmental Matters
We are subject to environmental regulations in the licensing and operation of the generation, transmission, and distribution facilities in which we have an interest, as well as the licensing and operation of the facilities in which we are a co-licensee. These environmental regulations are administered by local, state and federal regulatory authorities and may impact our generation, transmission, distribution, transportation and waste handling facilities on air, water, land and aesthetic qualities.

We cannot presently forecast the costs or other effects that environmental regulation may ultimately have on our existing and proposed facilities and operations. We believe that any such prudently incurred costs related to our utility operations would be recoverable through the ratemaking process. For additional information see Part II, Item 8, Note 16 - Commitments and Contingencies.

Seasonal Nature of Business
Our kilowatt-hour sales and revenues are typically higher in the winter and summer than in the spring and fall, as sales tend to vary with weather. Ski area and other winter-related recreational activities along with associated lodging, longer hours of darkness and heating loads from cold weather contribute to higher sales in the winter, while air conditioning generates higher sales in the summer. Consumption is least in the spring and fall, when there is decreased heating or cooling load.

Capital Expenditures
Our business is capital-intensive and requires annual construction expenditures to maintain the distribution system. Capital expenditures for the next five years are expected to range from $31.0 million to $56.0 million annually. These are subject to continuing review and adjustment and actual capital expenditures and timing may vary. Also see Part II, Item 7, Liquidity, Capital Resources and Commitments.

Number of Employees
Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers, represent our operating and maintenance employees. On December 31, 2007 we had 552 employees, of which 220 are represented by the union. On December 29, 2004, we agreed with our employees represented by the union to a new four-year contract, which expires on December 31, 2008.

Executive Officers of Registrant
The following sets forth the executive officers. There are no family relationships among the executive officers. The term of each officer is for one year or until a successor is elected. Officers are normally elected annually.

Name and Age	Office	Officer Since
Robert H. Young, 60	President and chief executive officer	1987
William J. Deehan, 55	Vice president - power planning and regulatory affairs	1991
Brian P. Keefe, 50	Vice president - government and public affairs	2006
Pamela J. Keefe, 42	Vice president, chief financial officer, and treasurer	2006
Joan F. Gamble, 50	Vice president - strategic change and business services	1998
Joseph M. Kraus, 52	Senior vice president - operations, engineering and customer service	1987
Dale A. Rocheleau, 49	Senior vice president, general counsel and corporate secretary	2003

Mr. Young joined the company in 1987 and was elected to his present position in 1995. Mr. Young also serves as president, CEO, and chair of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc. He serves as chair of the board of directors of our affiliates: VYNPC and The Home Service Store, Inc. He is also director of our affiliates: VELCO, and Vermont Electric Transmission Company, Inc. Mr. Young is director of the Edison Electric Institute, Inc., Chittenden Trust Company, University of Vermont, Vermont Business Roundtable, Associated Industries of Vermont, and the Weston Playhouse Theatre Company.

Mr. Deehan joined the company in 1985 with nine years of utility regulation and related research experience. Mr. Deehan was elected to his present position in May 2001.

Ms. Gamble joined the company in 1989 with 10 years of electric utility and related consulting experience. Ms. Gamble was elected to her present position in August 2001. Ms. Gamble also serves as vice president - strategic change and business services for our subsidiary: Eversant Corporation. She serves as a director for our subsidiaries: Eversant Corporation and SmartEnergy Water Heating Services, Inc.

Mr. Keefe joined the company in December 2006. Prior to being elected to his present position he served as vice president for governmental affairs from December 2006 to September 2007. Prior to joining the company, from 2000 to 2006, he served as a senior aide to U.S. Senator James M. Jeffords, focusing on energy, environment and economic development issues, and serving as liaison between Vermont constituents and Washington, D.C. policymakers.

Ms. Keefe joined the company in June 2006. Prior to joining the company, from 2003 to 2006, she served as senior director of financial strategy and assistant treasurer of IDX Systems Corporation ("IDX"); from 1999 to 2003 she served as director of financial planning and analysis and assistant treasurer at IDX. Ms. Keefe serves as director, vice president, chief financial officer, and treasurer of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc. She also serves as a director of our affiliate, VYNPC.

Mr. Kraus joined the company in 1981. Prior to being elected to his present position he served as senior vice president engineering and operations, general counsel, and secretary from May 2003 until November 2003. Mr. Kraus serves as director of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc.

Mr. Rocheleau joined the company in November 2003. Prior to being elected to his present position he served as senior vice president for legal and public affairs, and corporate secretary from November 2003 to September 2007. Prior to joining the company, he served as director and attorney at law from 1992 to 2003 with Downs Rachlin Martin, PLLC. Mr. Rocheleau serves as director, senior vice president, general counsel and corporate secretary of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and SmartEnergy Water Heating Services, Inc.

Energy Conservation and Load Management
The primary purpose of Conservation and Load Management programs is to offset need for long-term power supply and delivery resources that are more expensive to purchase or develop than customer-efficiency programs, including unpriced external factors such as emissions and economic risk. The Vermont Energy Efficiency Utility ("EEU"), created by the state of Vermont, began operation in January 2000. We have a continuing obligation to provide customer information and referrals, and coordination of customer service, power quality, and any other distribution utility functions, which may intersect with the EEU's activities.

We have retained the obligation to provide demand side management programs targeted at deferral of our transmission and distribution projects, as identified in Distributed Utility Planning ("DUP"). DUP is designed to ensure that safe, reliable delivery services are provided at least cost. The PSB recently approved a similar process for the bulk transmission lines and Transco. The PSB appointed three members of the public, along with representatives of the state's utilities, including us, to the newly created Vermont State Planning Committee to oversee that process. The Vermont Legislature, in 2006, also gave Efficiency Vermont authority to target the delivery of energy efficiency to specific geographic areas to defer transmission and distribution upgrades. This process began for the first time in 2007.

Unregulated Businesses
CRC's wholly owned subsidiary, Eversant Corporation, engages in the sale or rental of electric water heaters through a wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. to customers in Vermont and New Hampshire.

Recent Energy Policy Initiatives
Several laws have been passed since 2005 that impact electric utilities in Vermont. While provisions of recently passed laws are now being implemented, there is continued interest in new policies designed to reduce electricity consumption, promote renewable energy and reduce greenhouse gas emissions. We continue to monitor regional and federal proposals that may have an impact on our operations. See Part II, Item 7 - Recent Energy Policy Initiatives.

(d) Financial Information about Geographic Areas
We and our subsidiaries do not have any foreign operations or export sales.

(e) Available Information
We make available free of charge through the Internet Website, *www.cvps.com,* the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after electronically filing with the Securities and Exchange Commission ("SEC"). Access to the reports is available from the main page of the Internet Website through "Investor Relations." Our Corporate Ethics and Conflict of Interest Policy, Corporate Governance Guidelines, and Charters of the Audit, Compensation and Corporate Governance Committees are also available on the Internet Website. Access to these documents is available from the main page of our Internet Website under "About us" and then "Corporate Governance." Printed copies of these documents are also available upon written request to the Assistant Corporate Secretary at our principal executive offices. Our reports, proxy, information statements and other information are also available by accessing the SEC's Internet Website, *www.sec.gov*, or at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. Information regarding operation of the Public Reference Room is available by calling the SEC at 1-800-SEC-0330.

<u>Item 1A. Risk Factors</u>
We operate in a market and regulatory environment that involves significant risks, many of which are beyond our control, cannot be limited cost-effectively or may occur despite our risk-mitigation strategies. Each of the following risks could have a material effect on our performance.

Changes in regulatory or legislative policy could jeopardize our full recovery of costs: Under state law, we are entitled to charge rates that are sufficient to allow us an opportunity to recover reasonable operation and capital costs and a return on investment to attract needed capital and maintain our financial integrity, while also protecting relevant public interests. We prepare and submit periodic filings with the DPS for review and with the PSB for review and approval. The PSB may not approve the recovery of all costs incurred for the operation, maintenance, and construction of our regulated assets, as well as a return on investment. Increases in these costs, coupled with increases in energy prices, could lead to consumer or regulatory resistance to the timely recovery of such incurred costs, thereby adversely affecting our business and results of operations.

Risks related to liquidity: We have a six-month unsecured term note in the principal amount of $53.0 million with a major lending institution. The loan is payable June 30, 2008 and currently carries an adjustable borrowing rate. Pursuant to a commitment from the lending institution dated February 11, 2008, we have the sole option to extend the maturity of the term note to March 31, 2009. We used the proceeds from this note to acquire additional equity membership interests in Transco. There is a possibility that available capital may be too expensive to pursue further investments in Transco, in which we hope to maintain an equity ownership approximately equal to our load share. We may issue both debt and equity in 2008. There is a risk that the resulting cost of capital may negatively affect our results of operations. Further liquidity risk exists with our $46.0 million capital expenditure program budgeted for 2008. We currently have a $25.0 million credit facility to provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements in the form of funds borrowed and letters of credit. If we are unable to secure the necessary funding, we will need to review our corporate goals in response to this financial limitation. Other material risks to cash flow from operations include: loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; increases in net power costs largely due to lower-than-anticipated margins on sales revenue from excess power or an unexpected power source interruption; required prepayments for power purchases; and increases in performance assurance requirements described above, primarily as a result of high power market prices.

Our ability to access capital markets at attractive interest rates is important: We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Our business is capital intensive and we are dependent on our ability to access capital at rates and on terms we determine to be attractive. Heightened concerns about the energy industry, the level of borrowing by other energy companies and the market as a whole could limit our access to capital markets. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed, and future results of operations could be adversely affected.

Risks related to our power supply and wholesale power market prices: Our material power supply contracts are principally with Hydro-Quebec and VYNPC. The power supply contracts with VYNPC and Hydro-Quebec comprise the majority of our total annual energy (mWh) purchases. If one or both of these sources become unavailable for a period of time, there could be exposure to high wholesale power prices and that amount could be material. Additionally, this could significantly impact liquidity due to the potentially high cost of replacement power and performance assurance collateral requirements arising from purchases through ISO-New England or third parties. We could seek emergency rate relief from our regulators if this were to occur.

Our contract for power purchases from VYNPC ends in 2012, but there is a risk that the plant could be shut down earlier than expected if ENVY determines that it is not economical to continue operating the plant. Deliveries under the contract with Hydro-Quebec end in 2016, but the level of deliveries begin to decrease after 2012. There is a risk that future sources available to replace these contracts may not be as reliable and the price of such replacement power could be significantly higher than what we have in place today.

An inability to return our corporate credit rating to investment grade: In June 2005, Standard & Poor's Ratings Services ("S&P") lowered our corporate credit rating to below investment grade. We believe that restoration of our credit rating is critical to our long-term success. While our credit rating remains below investment grade, the cost of capital, which is ultimately passed on to our customers, will be greater than it otherwise would be. That, combined with other collateral requirements from creditors and for power purchases and sales, makes restoration of our credit rating critical. Looking ahead, as long-term power contracts with Hydro-Quebec and VYNPC begin to expire four to five years from now, these ratings become even more important. Access to needed capital is also more of a concern as a non-investment grade company, particularly in the current U.S. credit environment.

Active employee and retiree healthcare and pension costs are a significant part of our cost structure. The costs associated with healthcare or pension obligations could escalate at rates higher than anticipated, which could adversely affect our results of operations and cash flows.

Risk of adverse weather events: We serve a largely rural, rugged service territory with dense forestation that is subject to extreme weather. Our results of operations can be affected by changes in weather. Severe weather such as ice and snow storms, high winds and other natural disasters may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period. We typically receive the five-year average of storm restoration costs in our rates, but unexpected storms or extraordinarily severe weather can dramatically increase costs, with a significant lag before recovery begins. Given the small size of the company, these weather events could have a material impact on our financial condition. Weather conditions directly influence the demand for electricity.

Risks related to the regional and national economic conditions can have an unfavorable impact on us. Our business follows the economic cycles of the customers we serve. An economic downturn and increased cost of energy supply could adversely affect energy consumption and therefore impact our results of operations. Economic downturns or periods of high energy supply costs typically lead to reductions in energy consumption and increased conservation measures. These conditions could adversely impact the level of energy sales and result in less demand for energy delivery. Economic conditions in our service territory also impact our collections of accounts receivable and financial results.

The loss of key personnel or the inability to hire and retain qualified employees could have an adverse effect on our business, financial condition and results of operations. Our operations depend on the continued efforts of our employees. Retaining key employees and maintaining the ability to attract new employees are important to both our operational and financial performance. A significant portion of our workforce, including many workers with specialized skills maintaining and servicing the electrical infrastructure, will be eligible to retire over the next five to 10 years. Also, members of our management or key employees may leave the company unexpectedly. Such highly skilled individuals and institutional knowledge cannot be quickly replaced due to the technically complex work they perform.

Cash flow risk and capital distributions from our affiliates. Transco's ability to pay distributions will be subject to its financial condition and financial covenants in the various loan documents to which it is subject. Although Transco is a regulated business, Transco may not always have the resources needed to pay distributions with respect to the units in the same manner as VELCO has paid in the past.

Item 1B. Unresolved Staff Comments
None

Item 2. Properties
Our properties are operated as a single system that is interconnected by the transmission lines of Transco, New England Power and Public Service Company of New Hampshire. We own and operate 23 small generating stations in Vermont with a total current nameplate capability of 74.2 MW. Our joint ownership interests include: a 1.7769 percent interest in an oil-generating plant in Maine; a 20 percent interest in a wood-, gas- and oil-fired generating plant in Vermont; a 1.7303 percent interest in a nuclear generating plant in Connecticut; and a 47.52 percent interest in a transmission interconnection facility in Vermont. Additional information with respect to our properties is set forth under Part I, Item 1, Sources and Availability of Power Supply and is incorporated herein by reference.

Our electric transmission and distribution systems include about 617 miles of overhead transmission lines, about 8,367 miles of overhead distribution lines and about 439 miles of underground distribution lines, all of which are located in Vermont except for about 23 miles in New Hampshire and about 2 miles in New York.

We hold in fee all of our principal plants and important units, including those of our consolidated subsidiaries. Transmission and distribution facilities that are not located in or over public highways are, with minor exceptions, located on land owned in fee or pursuant to easements, most of which are perpetual. Transmission and distribution lines located in or over public highways are so located pursuant to authority conferred on public utilities by statute, subject to regulation of state or municipal authorities.

Substantially all of our utility property and plant is subject to liens under the First Mortgage Indenture.

Transco's properties consist of about 610 miles of high-voltage overhead and underground transmission lines and associated substations. The lines connect on the west with the lines of Niagara Mohawk Power Corporation at the Vermont-New York state line near Whitehall, New York, and Bennington, Vermont, and with the submarine cable of NYPA near Plattsburgh, New York; on the south and east with the lines of New England Power Company and PSNH; on the south with the facilities of Vermont Yankee; and on the northern border of Vermont with the lines of Hydro-Quebec near Derby, Vermont and through the Highgate converter station and tie line that we jointly own with several other Vermont utilities.

VELCO's wholly owned subsidiary, Vermont Electric Transmission Company, Inc. has about 52 miles of high-voltage DC transmission line connecting with the transmission line of Hydro-Quebec at the Quebec-Vermont border in the Town of Norton, Vermont; and connecting with the transmission line of New England Electric Transmission Corporation, a subsidiary of National Grid USA, at the Vermont-New Hampshire border near New England Power Company's Moore hydroelectric generating station.

Item 3. Legal Proceedings
We are involved in legal and administrative proceedings in the normal course of business and do not believe that the ultimate outcome of these proceedings will have a material adverse effect on our financial position, results of operations or cash flows.

Item 4. Submission of Matters to a Vote of Security Holders
There were no matters submitted to security holders during the fourth quarter of 2007.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

(a) Our common stock is listed on the New York Stock Exchange ("NYSE") under the trading symbol CV.

The table below shows the high and low sales price of our Common Stock, as reported on the NYSE composite tape by The Wall Street Journal, for each quarterly period during the last two years as follows:

	Market Price	
2007	High	Low
First Quarter	$29.19	$22.53
Second Quarter	$38.24	$29.10
Third Quarter	$41.05	$32.38
Fourth Quarter	$38.40	$25.95
2006		
First Quarter	$21.95	$17.89
Second Quarter	$21.90	$16.11
Third Quarter	$23.00	$18.01
Fourth Quarter	$23.92	$20.94

(b) As of December 31, 2007, there were 6,535 holders of our Common Stock, $6 par value.

(c) Common Stock dividends have been declared quarterly. Cash dividends of $0.23 per share were paid for all quarters of 2007 and 2006.

So long as any Senior Preferred Stock is outstanding, except as otherwise authorized by vote of two-thirds of such class, if the Common Stock Equity (as defined) is, or by the declaration of any dividend will be, less than 20 percent of Total Capitalization (as defined), dividends on Common Stock (including all distributions thereon and acquisitions thereof), other than dividends payable in Common Stock, during the year ending on the date of such dividend declaration, shall be limited to 50 percent of the Net Income Available for Dividends on Common Stock (as defined) for that year; and if the Common Stock Equity is, or by the declaration of any dividend will be, from 20 percent to 25 percent of Total Capitalization, such dividends on Common Stock during the year ending on the date of such dividend declaration shall be limited to 75 percent of the Net Income Available for Dividends on Common Stock for that year. The defined terms identified above are used herein in the sense as defined in subdivision 8A of our Articles of Association; such definitions are based upon our unconsolidated financial statements. As of December 31, 2007, the Common Stock Equity of our unconsolidated company was 57.7 percent of Total Capitalization.

Our First Mortgage Bond indenture contains certain restrictions on the payment of cash dividends on capital stock and other Restricted Payments (as defined). This covenant limits the payment of cash dividends and other Restricted Payments to our Net Income (as defined) for the period commencing on January 1, 2001 up to and including the month next preceding the month in which such Restricted Payment is to be declared or made, plus approximately $77.6 million. The defined terms identified above are used herein in the sense as defined in Section 5.09 of the Forty-Fourth Supplemental Indenture dated June 15, 2004; such definitions are based upon our unconsolidated financial statements. As of December 31, 2007, $62.9 million was available for such dividends and other Restricted Payments.

(d) The information required by this item is included in Part III, Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, herein.

(e) The performance graph showing our five-year total shareholder return required by this item is included in our Annual Report to Shareholders and is hereby incorporated by reference.

Item 6. Selected Financial Data
(dollars in thousands, except per share amounts)

	2007	2006	2005	2004	2003
Income Statement					
Operating revenues	**$329,107**	$325,738	$311,359	$302,286	$306,098
Income from continuing operations (a)	**$15,804**	$18,101	$1,410	$7,493	$17,148
Income from discontinued operations (b)	**-**	251	4,936	16,262	2,653
Net income	**$15,804**	$18,352	$6,346	$23,755	$19,801
Per Common Share Data					
Basic earnings from continuing operations	**$1.52**	$1.65	$0.09	$0.59	$1.35
Basic earnings from discontinued operations	**-**	.02	0.40	1.34	0.22
Basic earnings per share	**$1.52**	$1.67	$0.49	$1.93	$1.57
Diluted earnings from continuing operations	**$1.49**	$1.64	$0.08	$0.58	$1.32
Diluted earnings from discontinued operations	**-**	.02	0.40	1.32	0.21
Diluted earnings per share	**$1.49**	$1.66	$0.48	$1.90	$1.53
Cash dividends declared per share of common stock	**$0.92**	$0.69	$1.15	$0.92	$0.88
Balance Sheet					
Long-term debt (c)	**$112,950**	$115,950	$115,950	$115,950	$115,950
Capital lease obligations (c)	**$5,889**	$6,612	$6,153	$7,094	$8,115
Redeemable preferred stock (c)	**$2,000**	$3,000	$4,000	$6,000	$8,000
Total capitalization (c)	**$317,700**	$312,968	$351,527	$361,751	$350,560
Total assets	**$540,314**	$500,938	$551,433	$563,389	$534,635

(a) For 2005 includes a $21.8 million pre-tax charge to earnings ($11.2 million after-tax) related to a 2005 Rate Order. For 2004 includes a $14.4 million pre-tax charge to earnings ($8.4 million after-tax) related to termination of a long-term power contract with Connecticut Valley as a result of the January 1, 2004 sale of substantially all of its assets and franchise.

(b) For 2006 and 2005 includes Catamount, which was sold in the fourth quarter of 2005. For 2004 and 2003 includes Catamount and Connecticut Valley.

(c) Amounts exclude current portions.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

In this section we discuss our general financial condition and results of operations. Certain factors that may impact future operations are also discussed. Our discussion and analysis is based on, and should be read in conjunction with, the accompanying Consolidated Financial Statements. Also, please refer to our "Cautionary Statement Regarding Forward-Looking Information" section preceding Item 1 - Business of this Form 10-K.

COMPANY OVERVIEW

Our core business is the Vermont electric utility business. We typically generate most of our earnings through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-New England. The resale revenue generated from these sales helps to mitigate our power supply costs.

We are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. Our non-regulated wholly owned subsidiary Catamount Resources Corporation ("CRC") owns Eversant Corporation ("Eversant"), which operates a rental water heater business through its wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. This is not a significant business activity for us.

As a regulated electric utility, we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. The ability to increase our customer base is limited to acquisitions or growth within our service territory. Due to the nature of our customer base, weather and economic conditions are factors that can significantly affect retail sales revenue. Retail sales volume over the last 10 years has grown at an average rate of less than 1 percent per year ranging from slight decreases in some years to increases of 2 percent in others. We currently have sufficient power resources to meet our forecasted load requirements through 2011.

EXECUTIVE SUMMARY

Our consolidated 2007 earnings were $15.8 million, or $1.49 per diluted share of common stock. This compares to consolidated 2006 earnings of $18.4 million, or $1.66 per diluted share of common stock and consolidated 2005 earnings of $6.3 million, or 48 cents per diluted share of common stock. The primary drivers of earnings variances for the three years are described in Results of Operations below.

Restoring our corporate credit rating to investment grade is a top priority for us. During 2007, we made progress on several key strategic financial initiatives including:

- We filed a request for a 4.46 percent rate increase in May 2007 to ensure our retail rates are set at levels to recover our cost of service. In November 2007, we reached an agreement with the Vermont Department of Public Service ("DPS") that, among other things, decreased the rate increase request to 2.30 percent and provided for a 10.71 percent allowed rate of return on common equity, capped until our next rate proceeding or approval of an alternative regulation plan. In January 2008, the PSB approved the settlement agreement. See Retail Rates and Alternative Regulation.
- We filed an alternative regulation plan proposal in August 2007 that would allow an automatic quarterly review of our power costs and related rates and would annually adjust rates to reflect changes within predetermined limits from our allowed earnings level, replacing the traditional ratemaking process. The plan requires PSB approval. If approved, alternative regulation could help improve our credit ratings. Standard and Poor's, a national rating agency, has listed the lack of a power cost adjustment mechanism as one of the key factors negatively affecting our credit rating. See Retail Rates and Alternative Regulation.
- We made a $53.0 million investment in Vermont Transco LLC ("Transco"), the Vermont company that owns and operates the high-voltage transmission system in Vermont, in December 2007. This increased our direct ownership interest in Transco from 29.86 percent to 39.79 percent for a total investment of $78.8 million at December 31, 2007. We funded this investment by entering into a six-month unsecured Term Note in the principal amount of $53.0 million. Pursuant to a commitment from the lending institution dated February 11, 2008, we have the sole option to extend the maturity of the term note to March 31, 2009. See Liquidity, Capital Resources and Commitments.

Other financial initiatives that we continue to focus on include maintaining sufficient liquidity to support ongoing operations, investing in our electric utility infrastructure, planning for replacement power when our long-term power contracts expire, and evaluating opportunities to further invest in Transco.

Continued focus on these financial initiatives is critical to restoring our corporate credit rating to investment grade. We discuss these financial initiatives and the risks facing our business in more detail below.

RETAIL RATES AND ALTERNATIVE REGULATION

Our retail rates are set by the PSB after considering recommendations of Vermont's consumer advocate, the DPS. While our retail rates do not have fuel or power cost adjustment mechanisms, the PSB may approve the deferral of extraordinary costs incurred that might normally be expensed by unregulated businesses in order to match these expenses with future revenues. Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital.

Our retail rates at December 31, 2007 were based on a December 7, 2006 PSB Order, which provided for a 4.07 percent rate increase effective January 1, 2007 and an allowed rate of return on common equity of 10.75 percent capped until our next rate proceeding. The return on common equity of our regulated business did not exceed the allowed return for 2007. Our retail rates at December 31, 2006 and 2005 were based on a March 29, 2005 PSB Order that provided for a 2.75 percent rate decrease and an allowed rate of return on common equity capped at 10.0 percent. That Order also resulted in a $21.8 million pre-tax charge to earnings in 2005.

On November 29, 2007, we reached a settlement agreement with the DPS for a 2.3 percent retail rate increase (additional revenue of $6.4 million on an annual basis) effective February 1, 2008. We had filed a request for a 4.46 percent retail rate increase (additional revenue of $12.4 million on an annual basis). By working with the DPS, we were able to reduce our initial request while maintaining our commitment to make substantial additional investments in tree trimming and system upgrades. The settlement agreement provided for a 10.71 percent rate of return on common equity, capped until our next rate proceeding or approval of an alternative regulation plan. We also agreed to conduct an independent business process review to assure our cost controls are sufficiently challenging and that our regulated business is operating efficiently. On January 31, 2008, the PSB issued an Order approving the settlement agreement with the rate increase effective February 1, 2008. The independent business process review will take place during 2008.

In 2007, we implemented a PSB-approved retail rate design that results in a modest reallocation of annual revenues by customer class with greater emphasis on energy charges in reaction to wholesale market energy costs. The retail rate design also provides for a comprehensive study of the need for new service offerings and further rate redesign. This is based on fundamental changes in how costs are incurred to serve load based on availability of advanced metering and communications and structural changes in the New England wholesale power market. The study is due to the PSB in April 2008.

On August 31, 2007, we submitted an alternative regulation plan proposal for PSB approval. If approved, the plan would allow for quarterly rate adjustments to reflect power supply cost changes and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. The plan is designed to encourage efficiency in operations, and would replace the traditional ratemaking process, which is costly and time-consuming. The plan is currently under review and a PSB decision is expected in the third quarter of 2008. We cannot predict the outcome of that review at this time.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Cash Flows At December 31, 2007, we had cash and cash equivalents of $3.8 million and at December 31, 2006, we had cash and cash equivalents of $2.8 million. The primary components of cash flows from operating, investing and financing activities for both periods are discussed in more detail below.

Operating Activities: Operating activities provided $34.1 million in 2007. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items, provided $38.8 million. This amount was offset by operating activities related to working capital and other items that used $4.7 million. These items primarily included employee benefit funding of $7.9 million, of which $6.7 million was used for pension and postretirement medical trust fund contributions. This was offset by a $3.5 million decrease in special deposits and restricted cash used to meet performance assurance requirements for certain power contracts because we replaced cash deposited to meet collateral requirements with $1.5 million of additional letters of credit.

During 2006, operating activities provided $26.2 million. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items, provided $45.5 million. Additionally, special deposits and restricted cash used to meet performance assurance requirements for certain power contracts decreased by $15.5 million because the required amounts were lower and because we issued a $4.5 million letter of credit to meet a portion of the obligations. We also made $20.8 million in pension trust contributions, $5.2 million in postretirement benefit trust contributions, and $2.4 million in net postretirement medical and other benefit-related payments. Changes in working capital and other items used $6.4 million.

Investing Activities: Investing activities used $76.6 million in 2007, including $23.7 million for construction and plant expenditures and $53.0 million for our investment in Transco, partially offset by $0.1 million from other investments. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements.

During 2006, investing activities provided $32.1 million. We received $78.0 million in proceeds from net sales and maturities of available-for-sale securities. These proceeds included $50.0 million of available-for-sale securities that were used for the purchase of shares of our common stock through a tender offer that concluded in April 2006 using cash proceeds from the Catamount sale, and miscellaneous items contributed $1.2 million. We used $19.5 million for construction expenditures, $23.3 million for investments in Transco and $4.3 million for the acquisition of utility property.

Financing Activities: Financing activities provided $43.5 million in 2007. This was comprised of a $53.0 million short-term bridge loan and $2.1 million of stock issuance proceeds resulting from exercised stock options and the dividend reinvestment program. These items were partially offset by $9.7 million for dividends paid on common and preferred stock, $1.0 million preferred stock sinking fund payments, and $0.9 million for capital lease payments. Also, see Financing below.

During 2006, financing activities used $62.1 million, including $51.2 million for the tender offer, $10.2 million for dividends paid on common and preferred stock, $2.0 million for preferred stock sinking fund payments, and $1.0 million for capital lease payments. These items were partially offset by $1.3 million from stock issuance proceeds resulting from stock option exercises and $1.0 million from a decrease in preferred stock sinking fund payments.

Transco In October 2007, Transco received PSB approval to issue up to approximately $113.8 million of equity. In December 2007, we invested $53.0 million in Transco, increasing our direct equity interest in Transco from 29.86 percent to 39.79 percent. Our total direct and indirect interest in Transco increased from 44.34 percent to 45.68 percent.

Based on current projections, Transco expects to need additional capital in 2008 and 2009, but its projections are subject to change based on a number of factors, including revised construction estimates, timing of project approvals from regulators, and desired changes in its equity-to-debt ratio. While we have no obligation to make additional investments in Transco, we continue to evaluate investment opportunities on a case-by-case basis. Based on Transco's current projections, we could have an opportunity to make additional investments up to $2.0 million in 2008 and $20.0 million to $25.0 million in 2009, but the timing and amount depend on the factors discussed above and the amounts invested by other owners.

We are currently evaluating debt and equity issuance alternatives to fund these investments, but any investments that we make in Transco are voluntary, and subject to available capital and appropriate regulatory approvals.

Dividends Our dividend level is reviewed by our Board of Directors on a quarterly basis. It is our goal to ensure earnings in future years are sufficient to maintain our current dividend level.

Dividend Reinvestment Plan Our Dividend Reinvestment Plan was reinstated in April 2007. At that time, we elected to change the source of common shares to meet reinvestment needs under the Plan from open market purchases to Original Issue shares. In July 2007, we began using Treasury shares to meet reinvestment needs under the Plan. These elections are expected to result in additional cash flow of $1.0 million to $2.0 million annually.

Cash Flow Risks Based on our current cash forecasts, we will require outside capital in addition to cash flow from operations and our $25.0 million unsecured revolving credit facility in order to fund our business over the next year. Continued upheaval in the capital markets as described below could negatively impact our ability to obtain outside capital on reasonable terms. In addition, an extended unplanned Vermont Yankee plant outage or similar event could significantly impact our liquidity due to the potentially high cost of replacement power and performance assurance requirements arising from purchases through ISO-New England or third parties. In the event of an extended Vermont Yankee plant outage, we could seek emergency rate relief from our regulators. Other material risks to cash flow from operations include: loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; increases in net power costs largely due to lower-than-anticipated margins on sales revenue from excess power or an unexpected power source interruption; required prepayments for power purchases; and increases in performance assurance requirements.

Subprime Credit Crisis Due to recent market developments, including a series of rating agency downgrades of subprime U.S. mortgage-backed securities, the fair values of subprime-related investments have declined. This decline in fair value has become especially problematic for certain large financial institutions. We performed an assessment of our ability to obtain financing and currently expect to have access to liquidity in the capital markets at reasonable rates. We also have access to our unsecured revolving credit facility, which is not affected by general market conditions. However, sustained turbulence in the U.S. credit markets could limit or delay our access to capital.
We have also performed an assessment of the subprime exposure in our money market, benefit and nuclear decommissioning trust funds and have determined that a decline, if any, in fund fair value from subprime-related investments is not expected to be material.

Financing
Long-Term Debt: Substantially all utility property and plant are subject to liens under the First Mortgage Bonds. Associated scheduled sinking fund payments for the next five years are: $3.0 million in 2008, $5.5 million in 2009, zero in 2010, $20.0 million in 2011 and zero in 2012. Currently, we are not in default under the terms of any of our debt financing documents.

Credit Facility: We have a 364-day, $25.0 million unsecured revolving credit facility with a major lending institution pursuant to a Credit Agreement dated December 28, 2007. This replaces the previous credit facility, which was to expire in October 2008. Pursuant to a commitment from the credit facility bank dated February 11, 2008, we have the sole option to extend the maturity of the credit facility to March 31, 2009. Our obligation under the Credit Agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. Financing terms and costs include an annual commitment fee of 0.225 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.9 percent on the average daily amount of letters of credit outstanding. All interest, commission and fee rates are based on our unsecured long-term debt rating. The facility contains a material adverse effect clause, exercisable when our credit rating falls below investment grade, which permits the lender to deny a transaction at the point of request. Our credit rating is currently categorized as below investment grade. We are also required to collateralize any outstanding letter of credit in the event of a default under the credit facility. At December 31, 2007, there were no borrowings outstanding under the new credit facility, but $6.0 million of letters of credit were outstanding in support of performance assurance requirements associated with our power transactions. Under the old credit facility, a $5.0 million letter of credit, formerly in support of performance assurance requirements with a power counterparty, was outstanding until early January 2008.

Short-Term Note: We have a six-month unsecured term note in the principal amount of $53.0 million with a major lending institution. The loan is payable June 30, 2008 and currently carries an adjustable borrowing rate tied to overnight LIBOR plus a fixed spread that decreases as our credit rating improves. Other variable interest rate options are available to us, such as prime or federal funds rate plus a fixed spread. Fixed rate options are also available based on LIBOR for a time period of one, two or three months plus a fixed spread that decreases as our credit rating improves. There are no caps on these interest rate options. Pursuant to a commitment from the lending institution dated February 11, 2008, we have the sole option to extend the maturity of the term note to March 31, 2009. Our obligation under the term note is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. We used the proceeds from this note to acquire additional equity membership interests in Transco.

Refinancing Plans: Currently, we plan to issue first mortgage bonds to repay the $53.0 million short-term note described above. We are also reviewing options to support working capital needs resulting from investments in our distribution and transmission system.

Letters of Credit: In addition to the letters of credit we issued under the credit facility, we have three outstanding secured letters of credit issued by one bank, totaling $16.9 million in support of three separate issues of industrial development revenue bonds totaling $16.3 million. We pay an annual fee of 0.9 percent on the letters of credit, based on our secured long-term debt rating. In 2007, these letters of credit were extended by the bank to November 30, 2008. Pursuant to a bank commitment dated March 10, 2008, we have the sole option to extend the maturity of these letters of credit to November 30, 2009. The letters of credit are secured under our first mortgage indenture. At December 31, 2007, there were no amounts drawn under these letters of credit.

Covenants: At December 31, 2007, we were in compliance with all financial and non-financial covenants related to our various debt agreements, articles of association, letters of credit and credit facility.

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system. Capital expenditures in 2007 amounted to $23.7 million. Capital expenditures for the next five years are expected to range from $31.0 million to $56.0 million annually. The increased spending levels reflect our continued commitment to invest in system upgrades. These estimates are subject to continuing review and adjustment, and actual capital expenditures and timing may vary.

Contractual Obligations Significant contractual obligations as of December 31, 2007 are summarized below.

	Payments Due by Period (dollars in millions)				
Contractual Obligations	Total	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years
Long-term debt	$116.0	$3.0	$5.5	$20.0	$87.5
Interest on long-term debt (a)	91.4	7.1	13.6	11.8	58.9
Notes payable	63.8	63.8	-	-	-
Interest on notes payable	3.9	1.8	0.7	0.7	0.7
Redeemable preferred stock	3.0	1.0	2.0	-	-
Capital lease (c)	9.1	1.4	2.7	2.3	2.7
Operating leases - vehicle and other (b)	12.1	2.7	4.4	3.0	2.0
Purchased power contracts (d)	890.5	145.1	296.7	256.5	192.2
Nuclear decommissioning and other closure costs (e)	11.9	2.3	3.4	2.6	3.6
Total Contractual Obligations	$1,201.7	$228.2	$329.0	$296.9	$347.6

(a) Based on interest rates shown in Note 12 - Long-Term Debt.
(b) Includes interest payments on floating rate issues based on interest rates as of December 31, 2007.
(c) Includes interest payments based on imputed fixed interest rates at inception of the related leases.
(d) Forecasted power purchases under long-term contracts with Hydro-Quebec, VYNPC and various independent power producers. Our current retail rates include a provision for recovery of these costs from customers. The forecasted amounts in this table are based on certain assumptions including plant operations, weather conditions and availability of the transmission system, therefore actual results may differ. See Power Supply Matters for more information.
(e) Estimated decommissioning and all other closure costs related to our equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. Our current retail rates include a provision for recovery of these costs from customers. See Power Supply Matters for more information.

Pension and Postretirement Medical Benefit Obligations: The contractual obligation table above excludes estimated funding for pension and postretirement medical benefit obligations reflected in our consolidated balance sheet. These payments may vary based on changes in the fair value of plan assets (for pension obligations) and actuarial assumptions. In 2008, we expect to contribute a total of $4.9 million to our pension and postretirement medical trust funds; however, there is no minimum funding requirement for our pension plan. Based on our current funding level, we do not expect the provisions of the Pension Protection Act of 2006, passed into law in August 2006, to have a significant impact on our minimum required contributions in the near future. We expect that pension and postretirement medical contributions will not significantly exceed current funding levels for 2009 through 2012. Additional obligations related to our nonqualified pension plans are approximately $0.3 million per year.

Income Taxes: FIN 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48") unrecognized tax benefits are excluded from the table. At December 31, 2007, unrecognized state tax benefits of $0.6 million were recorded as FIN 48 liabilities. We are unable to make reasonable estimates of the period of cash settlement, if any, and the statute of limitations might expire without examination by the respective state taxing authority. These amounts are not currently subject to an examination by the state taxing authority. Also, at December 31, 2007, unrecognized federal tax benefits of $1.2 million were recorded as a reduction to the refund claims tax receivable. These unrecognized tax benefits relate to taxes receivable for which the refunds relating to the unrecognized tax benefits have not been received. Consequently, if the claim is denied there will be no refund forthcoming, and therefore no future cash inflow.

Capitalization Our capitalization for the past two years follows:

	(dollars in millions)		Percent	
	2007	2006	**2007**	2006
Common stock equity	**$189**	$179	**59%**	57%
Preferred stock*	**11**	12	**3%**	4%
Long-term debt*	**116**	116	**36%**	37%
Capital lease obligations*	**7**	7	**2%**	2%
	$323	$314	**100%**	100%

* includes current portion

Credit Ratings On December 19, 2007, Standard and Poor's Ratings Services ("S&P") reaffirmed our BB+ corporate credit rating, our BBB+ senior secured bond rating and stable outlook. In September 2007, S&P modified its criteria related to assigning ratings on first mortgage bonds that are higher than a company's corporate credit rating. S&P clarified the number of notches that bonds with a recovery rating of "1" or "1+" can be assigned above a company's corporate credit rating for a given rating category and reduced the collateral coverage required to achieve a "1+" rating. Our senior secured bond rating was raised from BBB to BBB+ at that time. In addition S&P maintained our business risk profile score of "5". S&P ranks utilities on a scale of "1" or "excellent" to "10" or "vulnerable". Our current credit ratings from S&P are shown in the table below. Credit ratings should not be considered a recommendation to purchase or sell stock.

Corporate Credit Rating	BB+
First Mortgage Bonds	BBB+
Preferred Stock	B+
Outlook	Stable

Performance Assurance At December 31, 2007, we had posted $6.4 million of collateral under performance assurance requirements for certain of our power contracts, of which $6.0 million was in the form of letters of credit, $0.3 million was cash and $0.1 million was represented by restricted cash. We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy for NEPOOL members. We are required to post collateral for all net purchased power transactions since our credit limit with ISO-New England is zero. Additionally, we are currently selling power in the wholesale market pursuant to contracts with third parties, and are required to post collateral under certain conditions defined in the contracts.

We are also subject to performance assurance requirements under our Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If Entergy Nuclear Vermont Yankee, LLC ("ENVY"), the seller, has commercially reasonable grounds to question our ability to pay for monthly power purchases, ENVY may ask VYNPC and VYNPC may then ask us to provide adequate financial assurance of payment. We have not had to post collateral under this contract.

Off-balance-sheet arrangements We do not use off-balance-sheet financing arrangements, such as securitization of receivables, nor obtain access to assets through special purpose entities. We have letters of credit that are described in Financing above. Additionally, we lease our vehicles and related equipment under one operating lease agreement. The individual leases are mutually cancelable one year from lease inception. Under the terms of the vehicle operating lease, we have guaranteed a residual value to the lessor in the event the leased items are sold. The guarantee provides for reimbursement of up to 87 percent of the unamortized value of the lease portfolio. Under the guarantee, if the entire lease portfolio had a fair value of zero at December 31, 2007, we would have been responsible for a maximum reimbursement of $8.6 million.

Commitments and Contingencies We have material power supply commitments for the purchase of power from VYNPC and Hydro-Quebec. These are described in Power Supply Matters below.

We own an equity interest in VELCO and Transco, which requires us to pay a portion of their operating costs. We own an equity interest in VYNPC and are obligated to pay a portion of VYNPC's operating costs. We also own equity interests in three nuclear plants that are permanently shut down and have completed decommissioning activities. We are responsible for paying our share of the costs associated with these plants. Our equity ownership interests are described in Note 3 - Investments in Affiliates.

Under the terms of the agreements with Catamount and Diamond Castle, we agreed to indemnify them, and certain of their respective affiliates as described in Note 16 - Commitments and Contingencies.

OTHER BUSINESS RISKS
In addition to the risks described above, we are also subject to regulatory risk and wholesale power market risk related to our Vermont electric utility business.

Regulatory Risk: Historically, electric utility rates in Vermont have been based on a utility's costs of service. As such, we are entitled to charge rates that are sufficient to allow us an opportunity to recover reasonable operation and capital costs and a reasonable return on investment to attract needed capital and maintain our financial integrity, while also protecting relevant public interests. We are subject to certain accounting standards that allow 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. There is no assurance that the PSB will approve the recovery of all costs incurred for the operation, maintenance, and construction of our regulated assets, as well as a return on investment. Adverse regulatory changes could have a significant impact on future results of operations and financial condition. See Critical Accounting Policies and Estimates.

The State of Vermont has passed several laws since 2005 that impact our regulated business and will continue to impact it in the future. Some changes include requirements for renewable energy supplies, and opportunities for alternative regulation plans. See Recent Energy Initiatives.

Wholesale Power Market Price Risk: Our material power supply contracts are with Hydro-Quebec and VYNPC. These contracts comprise the majority of our total annual energy (mWh) purchases. If one or both of these sources becomes unavailable for a period of time, there could be exposure to high wholesale power prices and that amount could be material.

We are responsible for procuring replacement energy during periods of scheduled or unscheduled outages of our power sources. Average market prices at the times when we purchase replacement energy might be higher than amounts included for recovery in our retail rates. If the amounts are material, we can request regulatory treatment of the costs for recovery from customers in future rates. Additionally, we had forced outage insurance in place during 2007 to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experienced unplanned outages during 2007. We have purchased similar coverage for 2008. See Power Supply Matters.

Power Supply Risk: Our contract for power purchases from VYNPC ends in 2012, but there is a risk that the plant could be shut down earlier than expected if ENVY determines that it is not economical to continue operating the plant. Hydro-Quebec contract deliveries end in 2016, but the average level of deliveries decreases by approximately 20 percent to 30 percent after 2012, and by approximately 85 percent after 2015. There is a risk that future sources available to replace these contracts may not be as reliable and the price of such replacement power could be significantly higher than what we have in place today.

ENVY has submitted a renewal application with the Nuclear Regulatory Commission ("NRC") for a 20-year extension of the Vermont Yankee plant operating license. ENVY also needs PSB approval to continue to operate beyond 2012. At this time, ENVY has not received approvals for the license extension, but in 2007 it initiated a 30-day exclusive negotiation period required by the original 2002 Vermont Yankee Memorandum of Understanding with the State of Vermont, for potential power purchases by the VYNPC sponsor companies, including us, in the plant's post-March 2012 life extension period. While the 30-day exclusive negotiation period has ended, we are continuing to participate in negotiations for a power contract beyond 2012 and cannot predict the outcome at this time.

There is also a risk that the Vermont Yankee plant could be shutdown earlier than expected if ENVY determines that it is not economical to continue operating the plant. An early shutdown would cause us to lose the economic benefit of an energy volume equal to close to 50 percent of our total committed supply and we would have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2007, the incremental replacement cost of lost power, including capacity, is estimated to average $57.7 million annually. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to any such shutdown. However, an early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion.

We, Green Mountain Power, the Vermont Public Power Supply Authority and HQ-Production are using a steering committee structure to develop background materials, terms and supporting actions needed in negotiations for future power purchases from Hydro-Quebec. We believe there is a high probability that we will have a new contract with Hydro-Quebec, and we have agreed to target completion of proposed draft terms by the end of 2008, with a proposed contract for review by the PSB in 2009. We cannot predict whether a contract will ultimately be approved or, if approved, the quantities of power to be purchased or the price terms of any purchases.

Market Risk: See Item 7A - Quantitative and Qualitative Disclosures About Market Risk.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements, and reported amounts of revenues and expenses during the reporting period. We believe that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions in matters that are inherently uncertain and that may change in subsequent periods.

Regulatory Accounting We prepare our financial statements in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") for our regulated business. Regulatory assets or liabilities arise as a result of a difference between accounting principles generally accepted in the U.S. and the accounting principles imposed by the regulatory agencies. Generally, regulatory assets represent incurred costs that have been deferred as they are probable of recovery in future rates. We record regulatory assets before approval for recovery has been received from the regulatory commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base our conclusions on a number of factors such as, but not limited to, changes in the regulatory environment, recent rate orders issued and the status of any potential new legislation. Regulatory liabilities represent obligations to make refunds to customers or amounts collected in rates for which the costs have not yet been incurred.

The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may have a material impact on our results of operations. In the event that we determine our regulated business no longer meets the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, the impact would, among other things, result in an extraordinary charge to operations of $16.9 million pre-tax at December 31, 2007. We believe our regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Revenues Revenues from the sale of electricity to retail customers are based on PSB-approved rates. Our revenues are recorded when service is rendered or when energy is delivered to customers. We accrue revenue based on estimates of electric service rendered and unbilled revenue at the end of each accounting period. This unbilled revenue is estimated each month based on daily generation volumes (territory load), estimated line losses and applicable customer rates. We estimate line losses at 5 percent. A 1 percent change in line losses would result in a $0.3 million change in revenues. Factors that could affect the estimate of unbilled revenues are seasonal weather conditions, changes in meter reading schedules, the number and type of customers scheduled for each meter reading date, estimated customer usage by class, applicable customer rates and estimated losses of energy during transmission and delivery. Unbilled revenues totaled $17.7 million at December 31, 2007 and $16.7 million at December 31, 2006.

Pension and Postretirement Medical Benefits We adopted FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158") as of December 31, 2006 as required. SFAS No. 158 requires an employer with a defined benefit plan or other postretirement plan to recognize an asset or liability on its balance sheet for the overfunded or underfunded status of the plan.

SFAS No. 158 also requires companies with early benefit measurement dates to change their measurement date in 2008 to correspond with their fiscal year-end and to record the financial statement impact of the change as an adjustment to retained earnings. We estimate that changing the annual benefit measurement date from September 30 to December 31 will result in a pre-tax charge of $1.4 million, of which $0.1 million will be recorded to retained earnings. In our most recent retail rate proceeding we received approval for recovery of the regulated utility portion of the impact resulting from the change in measurement date. Accordingly, we will record a regulatory asset of approximately $1.3 million in the first quarter of 2008 that will be amortized over five years, beginning in February 2008.

We use the fair value method to value all asset classes included in our pension and postretirement medical benefit trust funds. Assumptions are made regarding the valuation of benefit obligations and performance of plan assets. Delayed recognition of differences between actual results and those assumed is a required principle of these standards. This approach allows for systematic recognition of changes in benefit obligations and plan performance over the working lives of the employees who benefit under the plans. The following assumptions are reviewed annually, with a September 30 measurement date:

Discount Rate: The discount rate is used to record the value of benefits, which are based on future projections, in terms of today's dollars. The selection methodology used in determining the discount rate includes portfolios of "Aa" bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50.0 million in par value. As of September 30, 2007, the pension discount rate changed from 5.95 percent to 6.30 percent and the postretirement medical discount rate changed from 5.80 percent to 6.15 percent.

Expected Return on Plan Assets ("ROA"): We project the future ROA based principally on historical returns by asset category and expectations for future returns, based in part on simulated capital market performance over the next 10 years. The projected future value of assets reduces the benefit obligation a company will record. The expected ROA as of September 30, 2006 and 2007 was 8.25 percent. This rate was used to determine the annual expense for 2007 and will also be used to determine the 2008 expense.

Rate of Compensation Increase: We project employees' compensation increases, including annual increases, promotions and other pay adjustments, based on our expectations for future long-term experience reflecting general trends. This projection is used to estimate employees' pension benefits at retirement. The projected rate of compensation increase was 4.25 percent as of September 30, 2006 and 2007.

Health Care Cost Trend: We project expected increases in the cost of health care. For measurement purposes, we assumed a 9.5 percent annual rate of increase in the per capita cost of covered health care benefits for fiscal 2007, for pre-65 and post-65 claims costs. The rate is assumed to decrease 0.5 percent each year until 2010, and to decrease one percent in each of the subsequent years until an ultimate trend rate of 5.0 percent is reached in 2013.

Amortization of Gains/(Losses): The assets and liabilities of the pension and postretirement medical benefit plans are affected by changing market conditions as well as differences between assumed and actual plan experience. Such events result in gains and losses. Investment gains and losses are deferred and recognized in pension and postretirement medical benefit costs over a period of years. If, as of the annual measurement date, the plan's unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, the excess is amortized over the average remaining service period of active plan participants. This 10-percent corridor method helps to mitigate volatility of net periodic benefit costs from year to year. Asset gains and losses related to certain asset classes such as equity, emerging-markets equity, high-yield debt and emerging-markets debt are recognized in the calculation of the market-related value of assets over a five-year period. The fixed income assets are invested in longer-duration bonds to match changes in plan liabilities. The gains and losses related to this asset class are recognized in the market-related value of assets immediately. Also see Note 14 - Pension and Postretirement Medical Benefits.

Pension and Postretirement Medical Assumption Sensitivity Analysis Fluctuations in market returns may result in increased or decreased pension costs in future periods. The table below shows how, hypothetically, a 25-basis-point change in discount rate and expected return on assets would affect pension costs (dollars in thousands):

	25 Basis-point Increase in Discount Rate	25 Basis-point Decrease in Discount Rate	25 Basis-point Increase in Expected Return on Assets	25 Basis-point Decrease in Expected Return on Assets
Pension Plan				
Effect on projected benefit obligation as of October 1, 2007	$(1,743)	$1,620	-	-
Effect on 2007 net period benefit cost	$(202)	$210	$(204)	$204
Other Postretirement Medical Benefit Plans				
Effect on accumulated postretirement benefit obligation as of October 1, 2007	$(655)	$671	-	-
Effect on 2007 net periodic benefit cost	$(69)	$73	$(28)	$28

Derivative Financial Instruments We account for various power contracts as derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted and SFAS No. 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities*, (collectively "SFAS No. 133"). These statements require that derivatives be recorded on the balance sheet at fair value. We estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and market data and other assumptions. Fair value estimates involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future energy prices, including supply and demand levels and future price volatility. Based on a PSB-approved Accounting Order, we record the change in fair value of power contract derivatives as deferred charges or deferred credits on the balance sheet, depending on whether the fair value is an unrealized loss or gain. The corresponding offsets are recorded as current and long-term assets or liabilities depending on the duration.

During 2007, we entered into several forward power contracts that are derivatives. At December 31, 2007, the estimated fair value of all power contract derivatives was a net unrealized loss of $7.1 million ($7.8 million unrealized loss and $0.7 million unrealized gain). At December 31, 2006, the estimated fair value of power contract derivatives was an unrealized loss of $8.0 million. We estimate that a 10 percent increase in market prices would increase the net unrealized loss by $7.2 million, and a 10 percent decrease would decrease it by $5.4 million. Also see Item 7A - Quantitative and Qualitative Disclosures About Market Risk.

We are able to economically hedge our exposure to congestion charges that result from constraints on the transmission system with Financial Transmission Rights ("FTRs"). FTRs are awarded to the successful bidders in periodic auctions administered by ISO-New England, in which we participate. We have determined that FTRs are derivatives. The estimated fair value of FTRs that we held at December 31, 2007 and December 31, 2006 was zero since their auction clearing prices approximated fair value. We account for FTRs in the month that they settle in ISO-New England; these are included in Purchased Power on the Consolidated Statements of Income.

Environmental Reserves Environmental reserves are estimated and accrued using a probabilistic model when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our environmental reserve is for three sites in various stages of remediation. Our cost estimates for two of the sites are based on engineering evaluations of possible remediation scenarios and a Monte Carlo simulation. The liability estimate includes costs for remediation, monitoring and other future activities. At December 31, 2007, our reserve for the three sites was $1.9 million. It was $2.1 million at December 31, 2006. These estimates are based on currently available information from presently enacted state and federal environmental laws and regulations. The estimates are subject to revisions in future periods based on actual costs or new information concerning either the level of contamination at the site or newly enacted laws and regulations.

Reserve for Loss on Power Contract At December 31, 2007, we had a $9.6 million ($10.8 million at December 31, 2006) reserve for loss on a power contract, which relates to a terminated power contract resulting from the 2005 sale of a subsidiary's franchise. The loss represents our best estimate of the future sales revenue, in the wholesale market, and the cost of purchased power obligations. We base our calculation on assumptions about future power prices, the reallocation of power from the state-appointed purchasing agent and future load growth. We assess the carrying value of the liability regularly and continue to amortize the amount reserved on a straight line basis.

Income Taxes We adopted FIN 48 on January 1, 2007 as required. It did not have a material impact on our results of operations or statement of financial position. FIN 48 clarifies the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. The application of income tax law is complex and we are required to make many subjective assumptions and judgments regarding our income tax exposures. Changes in our subjective assumptions and judgments can materially affect amounts recognized on the income statement, balance sheet and statement of cash flows.

RESULTS OF OPERATIONS

The following is a detailed discussion of the results of operations for the past three years. This should be read in conjunction with the consolidated financial statements and accompanying notes included in this report.

Consolidated Summary Consolidated net income for the past three years follows (dollars in thousands, except earnings per share):

	2007	2006	2005
Income from continuing operations	**$15,804**	$18,101	$1,410
Income from discontinued operations	**-**	251	4,936
Net Income	**$15,804**	$18,352	$6,346
Earnings per share - basic:			
Earnings from continuing operations	**$1.52**	$1.65	$0.09
Earnings from discontinued operations	**-**	0.02	0.40
Earnings per share	**$1.52**	$1.67	$0.49
Earnings per share - diluted:			
Earnings from continuing operations	**$1.49**	$1.64	$0.08
Earnings from discontinued operations	**-**	0.02	0.40
Earnings per share	**$1.49**	$1.66	$0.48

The tables that follow provide a reconciliation of the primary year-over-year variances in diluted earnings per share for 2007 versus 2006 and 2006 versus 2005.

	2007 vs. 2006
2006 Earnings per diluted share	**$1.66**
Year-over-Year Effects on Earnings (a):	
Higher retail revenues - 4.07 percent rate increase Jan. 1, 2007	.62
Higher retail revenues - primarily volume	.34
Lower purchased power expense	.49
Higher equity in earnings	.19
Lower resale sales revenue	(.81)
Higher maintenance costs - primarily 2007 major storms	(.33)
Higher transmission costs	(.37)
2006 decrease in environmental reserves	(.09)
Other	(.21)
2007 Earnings per diluted share	**$1.49**

(a) The favorable impact of the April 2006 stock buyback is included in the individual EPS variances and not shown separately in the table above.

	2006 vs. 2005
2005 Earnings per diluted share	$.48
Year-over-Year Effects on Earnings:	
Higher resale sales revenue	.60
Higher equity in earnings - primarily Transco	.10
Decrease in environmental reserves	.09
Higher CRC earnings	.06
Other variances (a)	(.03)
Lower retail sales (a)	(.17)
Higher employee-related costs	(.22)
Discontinued operations	(.38)
Net impact of first-quarter 2005 Rate Order charges	.91
Impact of 2006 stock buyback (b)	.22
2006 Earnings per diluted share	$1.66

(a) Excluding 2005 Rate Order charges listed separately.
(b) Reflects the impact of the April 2006 stock buyback, which decreased common shares outstanding by about 18 percent.

Consolidated Income Statement Discussion The following includes a more detailed discussion of the components of our Consolidated Statements of Income and related year-over-year variances.

Operating Revenues The majority of operating revenues is generated through retail electric sales. Retail sales are affected by weather and economic conditions since these factors influence customer use. Resale sales represent the sale of power into the wholesale market normally sourced from owned and purchased power supply that is in excess of that needed by our retail customers. The amount of resale revenue is affected by the availability of excess power for resale, the types of sales we enter into and the contract price for those sales. Operating revenues and related mWh sales are summarized below.

	Revenue (dollars in thousands)			**mWh Sales**		
	2007	2006	2005	**2007**	2006	2005
Residential	**$136,359**	$124,520	$127,138	**1,003,055**	959,455	978,164
Commercial	**107,556**	103,432	105,363	**885,713**	888,537	902,062
Industrial	**36,064**	35,052	33,873	**425,356**	430,348	414,341
Other	**1,840**	1,768	1,618	**6,250**	6,125	5,535
Retail sales	**281,819**	264,772	267,992	**2,320,374**	2,284,465	2,300,102
Resale sales	**38,935**	53,149	41,457	**697,749**	1,031,171	662,570
Retail customer refund	**-**	-	(6,194)	**-**	-	-
Provision for rate refund	**(747)**	-	-	**-**	-	-
Other operating revenues	**9,100**	7,817	8,104	**-**	-	-
Total operating revenues	**$329,107**	$325,738	$311,359	**3,018,123**	3,315,636	2,962,672

The average number of retail customers is summarized below.

	2007	2006	2005
Residential	**135,591**	131,483	129,943
Commercial	**22,106**	21,506	21,034
Industrial	**37**	35	36
Other	**175**	173	171
Total	**157,909**	153,197	151,184

Comparative changes in operating revenues are summarized below (dollars in thousands):

	2007 vs. 2006	2006 vs. 2005
Retail sales:		
Volume (mWh)	**$4,960**	$(2,530)
Average price due to customer sales mix	**1,124**	1,164
Average price due to rate increase - January 1, 2007	**10,963**	-
Average price due to rate reduction - April 1, 2005	**-**	(1,854)
Subtotal	**17,047**	(3,220)
Resale sales	**(14,214)**	11,692
Retail customer refund	**-**	6,194
Provision for rate refund	**(747)**	-
Other operating revenues	**1,283**	(287)
Increase in operating revenues	**$3,369**	$14,379

2007 vs. 2006

Operating revenues increased $3.4 million, or 1.0 percent, due to the following factors:

- Retail sales increased $17.0 million resulting from a 4.07 percent rate increase as of January 1, 2007 and higher residential sales volume. Retail sales volume increased during 2007 largely due to an increase in the number of residential customers resulting from small service territory acquisitions in the second half of 2006 and customer growth in our service territory. Colder weather in the winter months in 2007 also contributed to increased retail sales volume. Customer sales mix increased average prices on retail sales because the unit price for residential sales is higher than those of other customer classes.
- Resale sales decreased $14.2 million resulting from less excess power available for resale. The decrease in excess power available for resale resulted from second quarter 2007 scheduled refueling outages at Vermont Yankee and Millstone Unit #3, decreased Vermont Yankee purchases due to a derate and unplanned outage during the third quarter of 2007, and lower output from our hydro facilities and from Independent Power Producers due to less rainfall compared to 2006. The increase in retail sales volume also reduced the power available for resale. Additionally, 2006 included approximately $8.4 million of Vermont Yankee uprate energy that was resold as described in Purchased Power below. This power was resold at the same prices that we paid for it.
- The provision for rate refund decreased revenue by $0.7 million. This amount was included in the 4.07 percent rate increase and is to be refunded to customers because the PSB disallowed our request to recover $1.5 million over two years for Vermont Yankee 2005 incremental refueling costs.
- Other operating revenues increased $1.3 million largely from the sale of additional transmission capacity on our share of Phase I/II transmission facility rights, offset by revenue for storm restoration performed for other utilities in 2006.

2006 vs. 2005

Operating revenues increased $14.4 million, or 4.6 percent, due to the following factors:

- Retail sales decreased $3.2 million due to lower customer use and a 2.75 percent rate reduction that began in April 2005, partly offset by higher average prices resulting from customer sales mix. Retail customers used less power due to milder winter and summer weather compared to 2005.
- Resale sales increased $11.7 million due to an increased volume of power that was not needed to serve retail customers. The largest increase in available energy for resale resulted from additional Vermont Yankee plant uprate power that we were required to purchase at market rates. We also had more available for resale due to the following factors: 1) more deliveries under the long-term contract with Hydro-Quebec; 2) increased output from the Vermont Yankee plant (excluding additional uprate power); 3) increased output from our hydro facilities and from Independent Power Producers due to heavy rainfall in 2006 compared to prior years; and 4) increased output from our jointly owned generating units largely due to Millstone Unit #3, which operated at close to 100 percent capacity in 2006 while it was idle for over a month in 2005 due primarily to a refueling outage in the fourth quarter of 2005. As described in Purchased Power below, revenue associated with resale sales was largely offset by the cost of the power.
- A $6.2 million customer refund in 2005 resulted in a favorable variance when comparing 2006 versus 2005.
- Other operating revenues decreased $0.3 million due to lower transmission revenue, partly offset by third-party billings associated with storm restoration performed for other utilities and lower reserves for pole attachments based on the fourth-quarter 2006 settlement of a tariff dispute.

Operating Expenses The variances in income statement line items that comprise operating expenses on the Consolidated Statements of Income are described below (dollars in thousands).

	2007 over/(under) 2006		2006 over/(under) 2005	
	Total Variance	**Percent**	Total Variance	Percent
Purchased power - affiliates and other	**$(8,726)**	**(5.1)**	$(2,195)	(1.3)
Production	**1,972**	**20.1**	(844)	(8.0)
Transmission - affiliates	**3,970**	*****	(1,518)	(56.4)
Transmission - other	**2,605**	**18.7**	674	5.1
Other operation	**4,775**	**9.8**	(7,909)	(14.0)
Maintenance	**5,898**	**26.8**	2,014	10.1
Depreciation	**(1,281)**	**(7.8)**	123	0.8
Taxes other than income	**782**	**5.4**	446	3.2
Income tax expense (benefit)	**(3,278)**	**(38.3)**	10,833	*
Total operating expenses	**$6,717**	**2.2**	$1,624	0.5

* variance exceeds 100 percent

Purchased Power - affiliates and other: Power purchases make up approximately 50 percent of total operating expenses. Most of these purchases are made under long-term contracts. These contracts and other power supply matters are discussed in more detail in Power Supply Matters below. Purchased power expense and volume are summarized below:

	Purchases (dollars in thousands)			**mWh Purchases**		
	2007	2006	2005	**2007**	2006	2005
VYNPC (a)	**$56,283**	$70,592	$57,266	**1,361,754**	1,689,390	1,430,155
Hydro-Quebec	**64,869**	64,297	58,377	**998,411**	998,365	832,357
Independent Power Producers	**22,796**	23,998	19,676	**176,169**	198,735	160,396
Subtotal long-term contracts	**143,948**	158,887	135,319	**2,536,334**	2,886,490	2,422,908
Other purchases	**16,018**	5,525	31,296	**219,186**	90,440	264,330
SFAS No. 5 loss amortizations	**(1,196)**	(1,196)	(1,196)	**-**	-	-
Maine Yankee, Connecticut Yankee and Yankee Atomic (a)	**2,588**	5,412	5,003	**-**	-	-
2005 Rate Order	**-**	-	2,441	**-**	-	-
Other	**(636)**	820	(1,220)	**-**	-	-
Total purchased power	**$160,722**	$169,448	$171,643	**2,755,520**	2,976,930	2,687,238

(a) Purchased power transactions with affiliates. Amounts shown in the table above are shown net of regulatory amortizations and deferrals including our share of VYNPC nuclear insurance settlements that we defer per a PSB Order.

Comparative changes in purchased power expense are summarized below (dollars in thousands):

	2007 vs. 2006	2006 vs. 2005
VYNPC	**$(14,309)**	$13,326
Hydro-Quebec	**572**	5,920
Independent Power Producers	**(1,202)**	4,322
Subtotal long-term contracts	**(14,939)**	23,568
Other purchases	**10,493**	(25,771)
Nuclear decommissioning costs	**(2,824)**	409
2005 Rate Order	**-**	(2,441)
Other	**(1,456)**	2,040
(Decrease) Increase in purchased power	**$(8,726)**	$(2,195)

2007 vs. 2006

Purchased power expense decreased $8.7 million, or 5.1 percent, due to the following factors:

- Purchased power costs under long-term contracts decreased $14.9 million in 2007 largely resulting from decreased Vermont Yankee plant output we purchase under the long-term power contract ("PPA") with Vermont Yankee Nuclear Power Corporation ("VYNPC"). The Vermont Yankee plant produced less power in 2007 due to a second-quarter scheduled refueling outage and a third quarter derate and unplanned outage. Also in 2006 we were required to purchase additional Vermont Yankee uprate power at market prices. That power was resold in the wholesale energy markets as described in Revenue above. Purchases from Independent Power Producers, most of which are hydro facilities, decreased resulting from less rainfall, partly offset by an increase in average rates. Purchases from Hydro-Quebec increased during 2007 resulting from an increase in the average energy price.

- Other purchases increased $10.5 million in 2007 resulting from replacement energy purchased during the Vermont Yankee outages and derate described above.
- Nuclear decommissioning costs are associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs decreased $2.8 million in 2007 due to lower collection schedules for Connecticut Yankee and Yankee Atomic. Decommissioning activities were completed at both plants during 2007. Maine Yankee decommissioning activity was completed in 2006.
- Other costs decreased $1.5 million principally due to a net accounting deferral in 2007 versus amortizations in 2006 for Millstone Unit #3 scheduled refueling outages. Based on approved regulatory accounting treatment, we defer the cost of incremental replacement energy costs of scheduled refueling outages, and amortize those costs through the next scheduled refueling outage, which typically spans an 18-month period. The last refueling outage at Millstone Unit #3 occurred in April and May 2007.

<u>2006 vs. 2005</u>
Purchased power expense decreased $2.2 million, or 1 percent, due to the following factors:

- Long-term contract purchases increased $23.6 million resulting from: 1) increased purchases under the PPA due to higher plant output including $8.4 million for additional plant uprate power that we were required to purchase at market prices and $4.9 million for higher plant output because the plant operated all year in 2006 but had a three-week refueling outage in the fourth quarter of 2005; 2) more deliveries under the VJO contract with Hydro-Quebec resulting from a change in the capacity factor from 65 percent to 80 percent for the contract year beginning November 1, 2005; and 3) more rainfall in 2006 versus 2005, which increased output from Independent Power Producers.
- Other purchases decreased $25.7 million because more power was available from long-term contract sources as described above and our owned sources. While there was no Vermont Yankee plant outage during 2006, we purchased high-cost replacement energy during the fourth quarter 2005 scheduled refueling outage.
- Nuclear decommissioning costs increased $0.4 million as a result of updated forecasts of decommissioning and other costs associated with these plants.
- Accounting entries associated with the 2005 Rate Order increased power costs by $2.5 million in 2005 with no comparable charges in 2006.
- Other power costs increased $2.0 million principally due to regulatory amortizations for Millstone Unit #3's scheduled refueling outages versus a net deferral in 2005.

Production: These costs represent the cost of fuel, operation and maintenance, property insurance, and property tax for our wholly and jointly owned production units.

The increase of $2.0 million for 2007 versus 2006 resulted primarily from premium expense of $1.3 million for Vermont Yankee outage insurance. This amount was amortized over 12 months beginning January 1, 2007. Fuel costs also increased $0.5 million. The variance for 2006 versus 2005 was not significant.

Transmission - affiliates: These expenses represent our share of the net cost of service of Transco as well as some direct charges for facilities that we rent. Transco allocates its monthly cost of service through the Vermont Transmission Agreement ("VTA"), net of NEPOOL Open Access Transmission Tariff ("NOATT") reimbursements and certain direct charges. The NOATT is the mechanism through which the costs of New England's high-voltage (so-called PTF) transmission facilities are collected from load-serving entities using the system and redistributed to the owners of the facilities, including Transco.

The increase of $4.0 million for 2007 versus 2006 is mostly due to higher rates, and lower reimbursements under NOATT. In 2006 transmission expenses from Transco decreased $1.5 million. This decrease was primarily due to third quarter 2006 NOATT reimbursements to Transco that were higher than its cost of service, partly due to the inclusion of the Northwest Reliability Project in reimbursements. Our share amounted to a $2.0 million reimbursement, which was recorded as a reduction in transmission expense for the third quarter of 2006.

Transmission - other: The majority of these expenses are for purchases of regional transmission service under the NOATT and charges for the Phase I and II transmission facilities. The increase of $2.6 million for 2007 versus 2006 primarily resulted from higher rates and overall transmission expansion in New England, partially offset by lower depreciation expense because the Phase I facility was fully depreciated in 2006. Other transmission expenses increased $0.7 million in 2006 versus 2005 due to a large increase in the NOATT rate starting in July 2006.
Other operation: These expenses are related to operating activities such as customer accounting, customer service, administrative and general activities, regulatory deferrals and amortizations, and other operating costs incurred to support our core business. The increase of $4.8 million for 2007 versus 2006 resulted from: 1) a third-quarter 2006 reduction in environmental reserves based on revised cost estimates; 2) higher bad debt expense related to a customer bankruptcy and, in 2006, recovery of a previous charge-off; and 3) higher other costs, including professional services. These were partially offset by lower pension and postretirement medical costs primarily due to additional contributions to the trust funds in March 2006, and lower external audit fees.

The $7.9 million decrease in 2006 versus 2005 primarily resulted from: 1) a $4.3 million increase in employee-related costs including pension, active and retiree medical, incentive compensation and the expected medical costs of long-term disability claims; 2) a $1.0 million increase in fees for professional services including external audit fees driven by Sarbanes-Oxley compliance and other contractor fees, partially offset by bondholder consent fees in 2005; and 3) a $0.7 million increase in customer accounting due principally to a customer bankruptcy; partially offset by 4) a $1.6 million third-quarter 2006 reduction in environmental reserves based on revised cost estimates; 5) a $10.7 million charge due to the March 2005 Rate Order from a revised calculation of overearnings for 2001 - 2003 and the 2004 gain resulting from termination of the power contract with Connecticut Valley; and 6) a $1.6 million decrease in net regulatory amortizations beginning in April 2005 per the March 2005 Rate Order, including deferrals of $0.7 million to match tree trimming and pole treating expenses with amounts currently recovered in rates.

Maintenance: These expenses are associated with maintaining our electric distribution system and include costs of our jointly owned generating and transmission facilities. The increase of $5.9 million for 2007 versus 2006 was primarily related to storm restoration costs from a major storm in April 2007 and storms in August 2007.

The increase of $2.0 million for 2006 versus 2005 resulted primarily from a $1.0 million increase in contractor costs for tree trimming, a $0.4 million increase in storm restoration costs, and a $0.6 million increase in other maintenance costs including stockroom maintenance and minor inventory items. Pursuant to the March 2005 Rate Order, beginning April 1, 2005, any differences between actual tree trimming costs and amounts included for recovery in retail rates are being deferred until our next rate proceeding. Therefore, the higher tree-trimming costs in 2006 were partially offset by the favorable impact of regulatory amortizations included in other operation above.

Depreciation: We use the straight-line remaining-life method of depreciation. The $1.3 million decrease for 2007 versus 2006 was due to lower rates resulting from a depreciation study, and the license extension of our jointly owned nuclear plant, Millstone Unit #3. There was no significant variance for 2006 versus 2005.

Taxes other than income: This is related primarily to property taxes and payroll taxes. There was no significant variance for 2007 versus 2006 or for 2006 versus 2005.

Income tax expense (benefit): Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods. The effective combined federal and state income tax rate was 29.9 percent for 2007, 35.6 percent for 2006 and 309.8 percent for 2005. The effective tax rate increased significantly in 2005 because we had a pre-tax loss of $0.7 million from continuing operations. On June 7, 2004, the State of Vermont enacted legislation that reduced the state income tax rate from 9.75 percent to 8.9 percent effective January 1, 2006, and from 8.9 percent to 8.5 percent effective January 1, 2007.

Other Income and Other Deductions These items are related to the non-operating activities of our utility business and the operating and non-operating activities of our non-regulated businesses through CRC. CRC's earnings were $0.5 million in 2007, $0.8 million in 2006 and $0.1 million in 2005. The variances in income statement line items that comprise other income and other deductions on the Consolidated Statements of Income are shown in the table below (dollars in thousands).

	2007 over/(under) 2006		2006 over/(under) 2005	
	Total Variance	**Percent**	Total Variance	Percent
Equity in earnings of affiliates	**$3,190**	**98.5**	$1,371	73.4
Allowance for equity funds during construction	**(73)**	**(60.8)**	41	51.9
Other income	**(1,674)**	**(30.5)**	1,366	33.2
Other deductions	**(80)**	**3.3**	1,151	(32.4)
Income tax expense	**(21)**	**1.5**	(1,255)	*
Total other income and deductions	**$1,342**	**26.8**	$2,674	*

* variance exceeds 100 percent

Equity in earnings of affiliates: These earnings are related to our equity investments including VELCO, Transco and VYNPC. The increase of $3.2 million for 2007 versus 2006 results principally from our 2006 investment in Transco. The $1.4 million increase for 2006 versus 2005 also resulted principally from investments that we made in Transco in 2006.

Other income: The decrease of $1.7 million for 2007 versus 2006 resulted primarily from a $1.3 million decrease in interest on temporary investments due to a lower portfolio balance resulting from the stock-buyback in 2006, and a $0.3 million gain on the sale of non-utility property in 2006.

The increase of $1.4 million for 2006 versus 2005 is primarily due to a $0.6 million increase in interest income from interest earned on the Catamount sale proceeds and a $0.3 million increase in gain on sales of non-utility property, partially offset by a $0.3 million decrease in interest on temporary investments resulting from lower cash balances.

Other Deductions: These items include supplemental retirement benefits and insurance, including changes in the cash surrender value of life insurance policies, non-utility expenses relating to rental water heaters, and miscellaneous other deductions. There were no significant variances for 2007 versus 2006.

Other deductions decreased $1.2 million for 2006 versus 2005 primarily due to a $0.4 million increase in 2005 impairments and realized losses associated with certain available-for-sale debt securities that were sold earlier than planned.

Benefit (expense) for income taxes: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods.

Interest Expense Interest expense includes interest on long-term debt, dividends associated with preferred stock subject to mandatory redemption, and interest on notes payable and the credit facility. The variances in income statement line items that comprise interest expense on the Consolidated Statements of Income are shown in the table below (dollars in thousands).

	2007 over/(under) 2006		2006 over/(under) 2005	
	Total Variance	**Percent**	Total Variance	Percent
Interest on long-term debt	**$1**	**0.0**	**$-**	0.0
Other interest	**270**	**25.1**	**(1,249)**	(53.8)
Allowance for borrowed funds during construction	**20**	**(51.3)**	**(13)**	50.0
Total interest expense	**$291**	**3.5**	**$(1,262)**	(13.3)

Other interest expense: The increase of $0.3 million for 2007 versus 2006 was principally due to regulatory carrying costs associated with an environmental reserve. The decrease of $1.2 million for 2006 versus 2005 included first-quarter 2005 charges of $1.2 million for carrying costs associated with the recalculation of overearnings for 2001 - 2003 per the March 2005 Rate Order.

Discontinued Operations Discontinued operations are associated with the December 2005 sale of Catamount Energy. Income from discontinued operations was zero in 2007, $0.3 million in 2006 and $4.9 million in 2005. Income in 2005 included a $5.6 million after-tax gain from the sale.

POWER SUPPLY MATTERS

Sources of Energy Our power supply portfolio includes a mix of base load and dispatchable resources. These sources are used to serve our retail electric load requirements plus any wholesale obligations into which we enter. We manage our power supply portfolio by attempting to optimize the use of these resources, and through wholesale sales and purchases to create a balance between our power supplies and load obligations.

Our current power forecast shows energy purchase and production amounts in excess of load obligations through 2011. Due to the forecasted excess, we enter into fixed-price forward sale transactions to reduce price (revenue) volatility in order to help stabilize our net power costs. We have entered into several forward sale contracts since January 1, 2007. The contracts vary from one to eight months with volumes from 10 MW to 65 MW depending upon our forecast energy excesses in the on-peak and off-peak periods of each month. Some of the contracts are contingent on Vermont Yankee plant output, eliminating the risks related to sourcing the sale if Vermont Yankee is not operating. Others are firm, thus potentially exposing us to the risk of market price volatility if we are not able to source the contracts with existing resources. Our main supply risk is with Vermont Yankee, and we have outage insurance through December 2008 to mitigate the market price risk during an unplanned outage through that time. In June 2007, we also entered into a forward contract for the purchase of replacement power during the scheduled Vermont Yankee plant outage in late 2008.

A breakdown of energy sources during the past three years follows.

	2007	2006	2005
Nuclear	**48%**	54%	51%
Hydro	**39%**	38%	35%
Oil and wood	**6%**	5%	5%
Other	**7%**	3%	9%
Total	**100%**	100%	100%

The following is a discussion of our primary sources of energy.

Vermont Yankee: We are purchasing our entitlement share of Vermont Yankee plant output under the terms of the PPA between ENVY and VYNPC. One remaining secondary purchaser continues to receive a small percentage (less than 0.2 percent) of our entitlement. An uprate in 2006 increased the plant's operating capacity by approximately 20 percent. The plant shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. We normally purchase replacement energy in the wholesale markets in New England during the scheduled outages.

Prices under the PPA increase $1 per megawatt-hour each calendar year, from $41 in 2008 to $45 in 2012. The PPA contains a provision known as the "low market adjuster", which calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price. Estimated annual purchases are expected to range from $59.3 million to $69.1 million for 2008 through 2011, and $17.5 million for 2012 when the contract expires. These estimates are based on projected mWh purchase volumes at PPA rates, plus estimates of VYNPC costs, primarily net interest expense and the cost of capital. Actual amounts may differ.

While the Vermont Yankee plant has an excellent operating record, future unscheduled outages or reduced output could occur at times when replacement energy costs are above the PPA rates. We have forced outage insurance to cover additional costs, if any, of obtaining replacement power if the plant experiences unplanned outages between January 1 and December 31, 2008. The coverage applies to unplanned outages of up to 30 consecutive calendar days per outage event. The total maximum coverage is $12.0 million, with a $1.2 million deductible. We had similar coverage in place for 2007 (total maximum coverage of $10.0 million with a $1.0 million deductible). There was a two-day unplanned outage at the plant in the third quarter of 2007 but no claims were made under the insurance contract because the incremental replacement power cost was below the deductible.

The PPA between ENVY and VYNPC contains a formula for determining the VYNPC power entitlement following the uprate. VYNPC and ENVY are seeking to resolve certain differences in the interpretation of the formula. At issue is how much capacity and energy VYNPC Sponsors receive under the PPA following the uprate. Based on VYNPC's calculations the VYNPC Sponsors should be entitled to slightly more capacity and energy than they are currently receiving under the PPA. We cannot predict the outcome of this matter at this time.

Hydro Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO is a group of Vermont electric companies, municipal utilities and cooperatives, including us. There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. We are not aware of any instance where this provision has been invoked by Hydro-Quebec.

Based on sellback contracts that were negotiated in the early phase of the VJO Power Contract, Hydro-Quebec obtained two options. The first gives Hydro-Quebec the right, upon four years' written notice, to reduce capacity deliveries by 50 MW, including the use of a like amount of our Phase I/II transmission facility rights. The second gives Hydro-Quebec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Quebec. This second option can be exercised five times through October 2015. Hydro-Quebec has not yet exercised these options.

Under the VJO Power Contract, the VJO and Hydro-Quebec had elections to change the annual load factor. Hydro-Quebec and the VJO have used all of their elections. Based on elections made by the VJO in 2006 and 2005, the load factor was at 80 percent for the contract years beginning November 1, 2006 and 2005. As of November 1, 2007, the annual load factor is 75 percent for the remainder of the contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described above. Estimated annual purchases are expected to range from $62.6 million to $67.5 million for 2008 through 2012. These estimates are based on certain assumptions including availability of the transmission system and scheduled deliveries, so actual amounts may differ.

Independent Power Producers: We purchase power from a number of Independent Power Producers that own qualifying facilities under the Public Utility Regulatory Policies Act of 1978. These qualifying facilities produce energy primarily using hydroelectric and biomass generation. Most of the power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Estimated annual purchases are expected to range from $21.7 million to $22.5 million for the years 2008 through 2012. These estimates are based on assumptions regarding average weather conditions and other factors affecting generating unit output, so actual amounts may differ.

Wholly owned hydro and thermal: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of about 74.2 MW. We operate all of these plants, which include: 1) 20 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.3 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 45.3 MW; 2) two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW; and 3) one diesel peaking unit with a nameplate capacity of 2.4 MW, which is currently in a deactivated status.

Jointly owned units: Our jointly owned units include: 1) a 1.7303 percent interest in Unit #3 of the Millstone Nuclear Power Station, a 1,155 MW nuclear generating facility; 2) a 20 percent interest in Joseph C. McNeil, a 54 MW wood-, gas- and oil-fired unit; and 3) a 1.7769 percent joint-ownership in Wyman #4, a 609 MW oil-fired unit. We account for these units on a proportionate consolidated basis using our ownership interest in each facility. Therefore, our share of the assets, liabilities and operating expenses of each facility are included in the corresponding accounts in our consolidated financial statements.

Dominion Nuclear Connecticut ("DNC") is the lead owner of Millstone Unit #3 with about 93.4707 percent of the plant joint-ownership. The plant's operating license has been extended from November 2025 to November 2045. We have an external trust dedicated to funding our share of future decommissioning costs, but we have suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. If a need for additional decommissioning funding is necessary, we will be obligated to resume contributions to the Trust Fund.

In October 2007, DNC filed an application with the NRC for a 7 percent uprate at Millstone Unit #3. If approved, we will be responsible for our share of the costs for the uprate and will receive our share of additional power from the uprate. The plant's next refueling outage is scheduled for the fall of 2008. During that outage, DNC plans to repair cracks that have been identified in the high-pressure turbines. Based on DNC's estimated repair costs, we do not expect our share of the costs to be material.

In January 2004, DNC filed, on behalf of itself and the two minority owners, including us, a lawsuit against the Department of Energy ("DOE") seeking recovery of costs related to storage of spent nuclear fuel arising from the failure of the DOE to comply with its obligations to commence accepting such fuel in 1998. A trial is expected to be held in August 2008. We continue to pay our share of the DOE Spent Fuel assessment expenses levied on actual generation and will share in recovery from the lawsuit, if any, in proportion to our ownership interest.

Other: Other sources of energy are largely related to short-term purchases from third parties in New England and the wholesale markets in ISO-New England. On an hourly basis, power is sold or bought through ISO-New England to balance our resource output and load requirements through the normal settlement process. On a monthly basis, we aggregate hourly sales and purchases and record them as operating revenues or purchased power, respectively. We are also charged for a number of ancillary services through ISO-New England, including costs for congestion, line losses, reserves and regulation that vary in part due to changes in the price of energy. The method for settling the cost of congestion and other ancillary services is administered by ISO-New England and is subject to change. Congestion and loss charges represent the cost of delivering energy to customers and reflect energy prices, customer demand, and the demands on transmission and generation resources.

In December 2006, ISO-New England implemented a new market mechanism referred to as the Forward Capacity Market ("FCM") to compensate owners of new and existing generation capacity, including demand reduction. ISO-New England believes that higher capacity payments in constrained areas will encourage the development of new generation where needed. Capacity requirements for load-serving entities, including us, are based on each entity's proportionate share of ISO-New England's prior year coincident peak demand. Based on specified rates through May 2010, we expect net FCM charges of approximately $1.5 million or more in 2008 and 2009.

We continue to monitor potential changes to the rules in the wholesale energy markets in New England. Such changes could have a material impact on power supply costs.

Decommissioned Nuclear Plants We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. As of December 31, 2007, all three have completed decommissioning activities and their operating licenses have been amended to operation of Independent Spent Fuel Storage Installation. They remain separately responsible for safe storage of each plant's spent nuclear fuel and waste at the sites until the DOE meets its obligation to remove the material from the site or until some other suitable storage arrangement can be developed. All three collect decommissioning and closure costs through FERC-approved wholesale rates charged under power purchase agreements with several New England utilities, including us. We believe, based on historical rate recovery, our share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. However, if the FERC disallows recovery of any of their costs, there is a risk that the PSB would disallow recovery of our share in retail rates.

Based on estimates from Maine Yankee, Connecticut Yankee and Yankee Atomic as of December 31, 2007, the total remaining approximate cost for decommissioning and other costs of each plant is as follows: $100.5 million for Maine Yankee, $350.1 million for Connecticut Yankee and $82.3 million for Yankee Atomic. Our share of the remaining obligations amounts to $2.0 million for Maine Yankee, $7.0 million for Connecticut Yankee and $2.9 million for Yankee Atomic. These estimates may be revised from time to time based on information available regarding future costs.

On October 4, 2006, the U.S. Court of Federal Claims issued a judgment in a spent nuclear fuel litigation, in the amounts of $34.2 million, $32.9 million and $75.8 million for Maine Yankee, Connecticut Yankee and Yankee Atomic, respectively, for years prior to 2002 for Maine Yankee, and 2001 for Connecticut Yankee and Yankee Atomic. This judgment in favor of these companies relates to the alleged failure of the DOE to provide for a permanent facility to store spent nuclear fuel. On December 4, 2006, the DOE filed its notice of appeal of the trial court's decision. As a result, none of the companies have recognized the damage awards on their books. On December 14, 2007, all three companies filed complaints against the DOE seeking damages starting from 2002 for Maine Yankee, and 2001 for Connecticut Yankee and Yankee Atomic, through a future trial date. We cannot predict the ultimate outcome of this decision on appeal or the subsequent complaints.

TRANSMISSION MATTERS

As a load-serving entity, we are required to share the costs related to the region's high-voltage transmission system through payments made under the NEPOOL Open Access Transmission Tariff ("NOATT"). Our allocation of NOATT costs, based on our percentage of network load, is a small fraction of New England's obligation. While this regional cost-sharing approach reduces our costs related to qualifying Vermont transmission upgrades, we pay a share of the costs for new and existing NOATT-qualifying facilities located elsewhere in New England.

There are a number of major transmission projects in Vermont being undertaken by Transco, some of which are already in service. Many of these projects, including most of the so-called Northwest Reliability Project, have been approved by NEPOOL for NOATT cost-sharing treatment. However, certain future Vermont transmission facilities may not qualify for such cost sharing, and those costs will be charged locally (within Vermont) rather than regionally. Our share of such costs will be determined by the classification of each project; some will be charged directly to specific utilities and some will be shared by all Vermont utilities.

Transco has been working with us on a project to solve load serving and reliability issues related to a 46-kV transmission line extending from Bennington to Brattleboro, Vermont, which we refer to as the Southern Loop. It serves about 25 percent of our load. We initiated a public involvement process in late 2005 to gain input on how best to improve and ensure reliable electric service in southern Vermont. Based on input from this process, in the fourth quarter of 2006 we filed a petition with the PSB for approval to purchase and install two synchronous condensers along the Southern Loop. The condensers are rotating machines similar to motors used to control power flow on electric power transmission systems without burning fuel. The project is expected to cost approximately $11.0 million and, subject to PSB approval, we plan to begin construction in 2008. The condensers will improve the reliability in the Stratton/Manchester area of the Southern Loop. VELCO is also working with us on a proposal to construct additional transmission lines in the area in order to improve reliability to the Brattleboro area of the Southern Loop. This includes the construction of a new line in the existing 345 kV corridor between Vermont Yankee in Vernon and our substation in Coolidge, and construction of a new substation in West Dummerston. Non-transmission alternatives including demand side management and generation are also being evaluated as a way to solve the reliability issues or defer the need for other transmission improvements.

The Regional Transmission Organization ("RTO") for New England began operating on February 1, 2005 pursuant to FERC Order 2000. We are a participant in this organization, which provides high-voltage transmission service on so-called Pool Transmission Facilities ("PTF") on a non-discriminatory basis throughout New England. Currently, costs are allocated for Regional Network Service ("RNS") each month based on each participant's percentage of network load. All utilities pay the same rate for facilities put into service after 1996, while the rate paid by a utility for facilities already in service at the end of 1996 is based, in part, on the cost of that utility's local portion of the PTF system. By March 2008, all users will pay the same rate for all facilities.

Under the RTO, Highgate and related facilities, owned by a number of Vermont utilities and Transco, are classified as the Highgate Transmission Facility with a five-year phase-in of RNS reimbursement treatment. At the end of the phase-in period, our net cost for Highgate will be based on our NEPOOL load ratio (about 2 percent) rather than our 46 percent ownership share of the facilities. Our share of reimbursements is expected to be about $1.6 million to $1.8 million for 2008 and beyond.

RECENT ENERGY POLICY INITIATIVES

In 2006, legislation was passed to encourage alternative regulation of utilities. It is intended to decouple the financial success of utilities from increased electricity sales, thereby encouraging energy conservation, and to establish a reasonably balanced system of risks and rewards to encourage utilities to operate as efficiently as possible. In August 2007, we proposed an alternative regulation plan. See Retail Rates and Alternative Regulation for additional information.

In 2007, a broad public engagement process led by the DPS was held in an effort to better understand Vermonters' views on energy issues. A report on this public input process was presented by the DPS to the Vermont Legislature, the governor and state utilities in January 2008. The report showed a high level of support for new renewable generation, broad concerns about the environmental impacts of fossil- and nuclear-fueled generation, and continued support for energy efficiency programs. The report, along with regulatory and legislative policy direction, will help inform our choices as we consider future power supply options.

In 2007, the Vermont Legislature passed Act 79, *An Act Relating to Establishing the Vermont Telecommunications Authority to Advance Broadband and Wireless Communications Infrastructure throughout the State.* This new law sets a goal of providing statewide broadband coverage by the end of 2010. The PSB is now examining the use or role of the electric utilities to facilitate deployment of high-speed telecommunications infrastructure and services throughout the state. In addition, the Vermont Legislature is currently considering a bill to: 1) clarify rate and tariff policies for telecommunication equipment on utility transmission and generation facilities; 2) better coordinate utility and telecommunication planning for new construction of distribution facilities; and 3) establish a mechanism for expediting the installation of communications facilities within existing easements.

On February 28, 2008, the Vermont Legislature gave final approval to S. 209, "the Vermont Energy Efficiency and Affordability Act." The bill is expected to be signed into law by the governor in 2008. Provisions of the bill include, among other things:

- A requirement that, by 2013, new renewable resources must provide electricity equivalent to 5 percent of the state's total retail electricity sales in 2005. This is in addition to a current requirement that such resources must produce the electricity equivalent to the state's incremental sales growth after 2005.
- Expansion of the state's net metering law by increasing the size of qualifying facilities from a capacity of 15 kW to 250 kW, and by authorizing group net metering for customers within a single utility service area;
- A requirement that Vermont electric utilities install advanced smart metering equipment capable of sending two-way signals and sufficient to support advanced time-of-use pricing. (We are working with regulators to develop an appropriate smart-metering plan and schedule for implementation in our service territory.)
- An expansion of the state's energy efficiency programs from the existing focus on electricity use to include thermal uses such as oil, propane, natural gas and wood used to heat homes and businesses. Funding for these new programs comes from existing sources, along with expected revenues from the Regional Greenhouse Gas Initiative.
- A state goal for all energy sectors to, by the year 2025, produce 25 percent of the energy consumed within the state from renewable energy sources, particularly from Vermont's farms and forests.

Currently there are hearings in the Vermont Legislature regarding Vermont Yankee, including changes to its corporate structure, and how to devise a plant inspection process to reassure Vermonters that it can continue to operate safely and reliably. By state law, the Vermont Legislature and the PSB must affirmatively approve continued operation of Vermont Yankee after its license expires in March 2012.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1 - Business Organization and Summary of Significant Accounting Policies to the accompanying Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We consider our most significant market-related risks to be associated with wholesale power markets, equity markets and interest rates. Fair and adequate rate relief through cost-based rate regulation can limit our exposure to market volatility. Below is a discussion of the primary market-related risks associated with our business.

Wholesale Power Market Price Risk Our most significant power supply contracts are with Hydro-Quebec and VYNPC. Combined, these contracts amounted to approximately 70 to 80 percent of our total energy (mWh) purchases in 2007, 2006 and 2005. The contracts are described in more detail in Item 7, Power Supply Matters and Item 8, Note 16 - Commitments and Contingencies. Summarized information regarding power purchases under these contracts follows.

		2007		2006		2005	
	Expires	**mWh**	**$/mWh**	mWh	$/mWh	mWh	$/mWh
Hydro-Quebec (a)	2016	**998,411**	**$64.97**	998,365	$64.40	832,357	$70.16
VYNPC (b)	2012	**1,361,754**	**$41.33**	1,689,390	$41.78	1,430,155	$40.05

(a) Under the terms of the Hydro-Quebec contract, there is a defined energy rate that escalates at the general inflation rate based on the U.S. Gross National Product Implicit Price Deflator ("GNPIPD") and capacity rates are constant with the potential for small reductions if interest rates decrease below average values set in prior years.

(b) Under the terms of the contract with VYNPC the energy price generally ranges from 3.9 cents to 4.5 cents per kilowatt-hour through 2012. Effective November 2005, the contract prices are subject to a "low-market adjuster" mechanism.

Currently, our power forecast shows energy purchase and production amounts in excess of our load requirements through 2011. Because of this projected power surplus, we enter into forward sale transactions from time to time to reduce price volatility of our net power costs. The effect of increases or decreases in average wholesale power market prices is highly dependent on whether or not our net power resources at the time are sufficient to meet load requirements. If they are not sufficient to meet load requirements, such as when power from Vermont Yankee is not available as expected, we are in a purchase position. In that case, increased wholesale power market prices would increase our net power costs. If our net power resources are sufficient to meet load requirements, we are in a sale position. In that case, increased wholesale power market prices would decrease our net power costs.

We account for some of our power contracts as derivatives under the guidance of SFAS No. 133. These derivatives are described in Item 7, Critical Accounting Policies and Estimates. Summarized information related to the fair value of power contract derivatives is shown in the table below (dollars in thousands):

	Forward Sale Contracts	**Forward Purchase Contracts**	**Hydro-Quebec Sellback #3**	**Total**
Total fair value at December 31, 2006 - unrealized loss	$(3,962)	$(304)	$(3,731)	$(7,997)
Plus new contracts entered into during 2007	409	(502)	-	(93)
Less amounts settled during 2007	1,329	304	-	1,633
Change in fair value during 2007	187	21	(861)	(653)
Total fair value at December 31, 2007 - unrealized loss, net	$(2,037)	$(481)	$(4,592)	$(7,110)
Source	Over-the-counter quotations	Over-the-counter quotations	Quoted market data and valuation methodologies	
Estimated fair value at December 31, 2007 for changes in projected market price:				
10 percent increase	$(5,045)	$51	$(9,262)	$(14,256)
10 percent decrease	$970	$(1,012)	$(1,690)	$(1,732)

Per a PSB-approved Accounting Order, changes in fair value of derivatives are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the fair value is an unrealized loss or unrealized gain, with an offsetting amount recorded as a decrease or increase in the related derivative asset or liability.

Investment Price Risk We are subject to investment price risk due to equity market fluctuations and interest rate changes. Those risks are described in more detail below.

Interest Rate Risk: Interest rate changes could impact the value of the debt securities in our pension and postretirement medical trust funds and the calculations related to estimated pension and other benefit liabilities, affecting pension and other benefit expenses, contributions to the external trust funds and ultimately our ability to meet future pension and postretirement benefit obligations. We have adopted a diversified investment policy whose goal is to mitigate these market impacts. See Item 7, Critical Accounting Policies and Estimates, and Item 8, Note 14 - Pension and Postretirement Medical Benefits.

Interest rate changes could also impact the value of the debt securities in our Millstone Unit #3 decommissioning trust. At December 31, 2007, the trust held debt securities in the amount of $1.4 million.

As of December 31, 2007, we had $16.3 million of Industrial Development Revenue bonds outstanding, of which $10.8 million have an interest rate that floats monthly with the short-term credit markets and $5.5 million that floats every five years with comparable credit markets. Our short-term note of $53.0 million currently carries an adjustable borrowing rate. All other utility debt has a fixed rate. There are no interest locks or swap agreements in place.

The table below provides information about interest rates on our long-term debt, Industrial Development Revenue bonds and short-term note (dollars in millions).

	Expected Maturity Date						
	2008	2009	2010	2011	2012	Thereafter	Total
Fixed Rate ($)	**$6.9**	$6.7	$6.7	$6.1	$5.7	$58.9	$91.0
Average Fixed Interest Rate (%)	**6.22%**	6.22%	6.22%	6.36%	6.50%	7.08%	
Variable Rate ($)	**$2.0**	$0.5	$0.4	$0.4	$0.3	$0.7	$4.3
Average Variable Rate (%)	**4.68%**	3.43%	3.28%	3.28%	3.28%	3.42%	

Equity Market Risk: As of December 31, 2007, our pension trust held marketable equity securities in the amount of $60.6 million, our postretirement medical trust funds held marketable equity securities in the amount of $8.7 million, and our Millstone Unit #3 decommissioning trust held marketable equity securities of $4.2 million. We also maintain a variety of insurance policies in a Rabbi Trust with a current value of $7.5 million to support various supplemental retirement and deferred compensation plans. The current values of certain policies are affected by changes in the equity market.

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Central Vermont Public Service Corporation

We have audited the accompanying consolidated balance sheets of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and consolidated financial statement schedule based on our audits. We did not audit the financial statements of Vermont Transco LLC ("Transco"), and Vermont Electronic Power Company, Inc. ("Velco"), the Company's investments in which are accounted for by use of the equity method. The Company's equity of $78,784,000, and $11,534,000 in Transco and Velco and as of December 31, 2007, respectively, and of $4,482,000, and $1,404,000 in these companies' net income for the year-ended December 31, 2007 are included in the accompanying consolidated financial statements. Those financial statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Transco, and Velco, is based solely on the reports of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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 and the reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of Central Vermont Public Service Corporation and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standard No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*, as of December 31, 2006.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board ("FASB") Interpretation 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*, effective January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2008 expresses an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Philadelphia, Pennsylvania
March 11, 2008

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(dollars in thousands, except share data)

	For the Years Ended		
	2007	2006	2005
Operating Revenues	**$329,107**	$325,738	$311,359
Operating Expenses			
Purchased Power - affiliates	**58,361**	75,527	61,140
Purchased Power - other sources	**102,361**	93,921	110,503
Production	**11,700**	9,728	10,572
Transmission - affiliates	**5,144**	1,174	2,692
Transmission - other	**16,524**	13,919	13,245
Other operation	**53,457**	48,682	56,591
Maintenance	**27,937**	22,039	20,025
Depreciation	**15,217**	16,498	16,375
Taxes other than income	**15,140**	14,358	13,912
Income tax expense (benefit)	**5,291**	8,569	(2,264)
Total Operating Expenses	**311,132**	304,415	302,791
Utility Operating Income	**17,975**	21,323	8,568
Other Income			
Equity in earnings of affiliates	**6,430**	3,240	1,869
Allowance for equity funds during construction	**47**	120	79
Other income	**3,813**	5,487	4,121
Other deductions	**(2,481)**	(2,401)	(3,552)
Income tax expense	**(1,458)**	(1,437)	(182)
Total Other Income	**6,351**	5,009	2,335
Interest Expense			
Interest on long-term debt	**7,197**	7,196	7,196
Other interest	**1,344**	1,074	2,323
Allowance for borrowed funds during construction	**(19)**	(39)	(26)
Total Interest Expense	**8,522**	8,231	9,493
Income from continuing operations	**15,804**	18,101	1,410
Income from discontinued operations, net of income taxes (includes gain on disposal of $5,607 in 2005)	**-**	251	4,936
Net Income	**15,804**	18,352	6,346
Dividends declared on preferred stock	**368**	368	368
Earnings available for common stock	**$15,436**	$17,984	$5,978
Per Common Share Data:			
Basic earnings from continuing operations	**$1.52**	$1.65	$0.09
Basic earnings from discontinued operations	**-**	0.02	0.40
Basic earnings per share	**$1.52**	$1.67	$0.49
Diluted earnings from continuing operations	**$1.49**	$1.64	$0.08
Diluted earnings from discontinued operations	**-**	0.02	0.40
Diluted earnings per share	**$1.49**	$1.66	$0.48
Average shares of common stock outstanding - basic	**10,185,930**	10,756,027	12,258,508
Average shares of common stock outstanding - diluted	**10,350,191**	10,827,182	12,366,315
Dividends declared per share of common stock	**$0.92**	$0.69	$1.15

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	For the Years Ended		
	2007	2006	2005
Net Income	**$15,804**	$18,352	$6,346
Other comprehensive income, net of tax:			
Defined benefit pension and postretirement medical plans			
Portion reclassified through amortizations, included in benefit costs and recognized in net income:			
Actuarial losses, net of income taxes of $12 in 2007, $0 in 2006 and 2005	**19**	-	-
Prior service cost, net of income taxes of $9 in 2007, $0 in 2006 and 2005	**13**	-	-
Transition benefit obligation, net of income taxes of $0 in 2007, $0 in 2006 and 2005	**1**	-	-
Portion recognized due to year-end remeasurement of plan assets and obligations:			
Actuarial losses, net of income taxes of $93 in 2007, $0 in 2006 and 2005	**136**	-	-
Prior service cost, net of income taxes of $(1) in 2007, $0 in 2006 and 2005	**(2)**	-	-
Transition benefit obligation, net of income taxes of $0 in 2007, $0 in 2006 and 2005	**(1)**	-	-
Minimum pension liability adjustment, net of income taxes of $0 in 2007, $203 in 2006 and $(50) in 2005	**-**	285	(74)
Defined benefit pension plans, net	**166**	285	(74)
Investment securities			
Unrealized holding gain (loss), net of income taxes of $0 in 2007, $60 in 2006 and $(43) in 2005	**-**	89	(64)
Less reclassification adjustment for (gains) losses included in net income, net of income taxes of $0 in 2007, $(45) in 2006 and $215 in 2005	**-**	(69)	316
Foreign currency			
Other comprehensive loss from discontinued operations net of income taxes of $0 in 2007, $0 in 2006 and $(178) in 2005	**-**	-	(462)
	166	305	(284)
Comprehensive Income	**$15,970**	$18,657	$6,062

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

(dollars in thousands)	For the Years Ended December 31		
Cash flows provided (used) by:	**2007**	2006	2005
OPERATING ACTIVITIES			
Net income	**$15,804**	$18,352	$6,346
Deduct: Income from discontinued operations, net of income taxes	**-**	(251)	(4,936)
Income from continuing operations	**15,804**	18,101	1,410
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of affiliates	**(6,430)**	(3,240)	(1,869)
Distributions received from affiliates	**4,894**	2,106	1,938
Depreciation	**15,217**	16,498	16,375
Amortization of capital leases	**873**	1,096	1,020
Deferred income taxes and investment tax credits	**2,726**	3,820	(1,835)
Regulatory and other amortization, net	**(5,097)**	(3,354)	(3,113)
Non-cash employee benefit plan costs	**6,794**	9,997	7,973
Environmental reserve adjustment	**-**	(1,609)	-
Share-based compensation	**545**	899	108
Charge related to Rate Order (net of $6.5 million customer refund)	**-**	-	15,312
Other non-cash expense and (income), net	**3,434**	1,123	500
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable and unbilled revenues	**(366)**	(5,456)	590
Decrease in accounts payable	**(504)**	(252)	(1,798)
Increase in accounts payable - affiliates	**1,183**	620	638
Decrease (increase) in other current assets	**614**	(761)	793
Decrease (increase) in special deposits and restricted cash for power collateral	**3,519**	15,512	(19,094)
Employee benefit plan funding	**(7,878)**	(28,420)	(6,980)
Decrease in other current liabilities	**(2,362)**	(893)	(6,380)
Decrease (increase) in other long-term assets	**40**	(169)	127
Increase (decrease) in other long-term liabilities and other	**1,086**	551	(446)
Net cash provided by operating activities of continuing operations	**34,092**	26,169	5,269
INVESTING ACTIVITIES			
Construction and plant expenditures	**(23,663)**	(19,504)	(17,558)
Investments in available-for-sale securities	**(20,797)**	(256,431)	(277,812)
Proceeds from sale of available-for-sale securities	**20,670**	334,390	238,906
Investment in affiliates (Transco)	**(53,000)**	(23,291)	-
Acquisition of utility property (Rochester Electric and Vermont Electric Coop)	**-**	(4,306)	-
Investment in discontinued operations	**-**	-	(5,900)
Note receivable repayment from (advanced to) discontinued operations	**-**	-	11,000
Decrease (increase) in restricted cash	**-**	883	(883)
Return of capital from investments in affiliates and other	**170**	359	435
Net cash (used for) provided by investing activities of continuing operations	**(76,620)**	32,100	(51,812)
FINANCING ACTIVITIES			
Proceeds from issuance of common stock	**2,131**	1,267	1,163
Treasury stock acquisition - tender offer	-	(51,186)	-
Retirement of preferred stock subject to mandatory redemption	**(1,000)**	(2,000)	(2,000)
Net change in special deposits held for preferred stock redemptions	-	1,000	-
Common and preferred dividends paid	**(9,734)**	(10,164)	(12,140)
Proceeds from short-term bridge loan	**53,000**	-	-
Proceeds from borrowings under revolving credit facility	**45,600**	18,100	13,400
Repayments under revolving credit facility	**(45,600)**	(18,100)	(13,400)
Reduction in capital lease obligations and other	**(865)**	(963)	(1,045)
Net cash provided by (used for) financing activities of continuing operations	**43,532**	(62,046)	(14,022)
DISCONTINUED OPERATIONS			
Decrease in cash resulting from deconsolidation of Catamount	**-**	-	(16,373)
Net cash provided by operating activities	**-**	-	3,830
Net cash provided by investing activities (includes proceeds from sales of discontinued operations, net of transaction costs)	**-**	-	45,942
Net cash provided by financing activities	**-**	-	22,020
Net cash provided by discontinued operations	**-**	-	55,419
Net increase (decrease) in cash and cash equivalents	**1,004**	(3,777)	(5,146)
Cash and cash equivalents at beginning of the period	**2,799**	6,576	11,722*
Cash and cash equivalents at end of the period	**$3,803**	$2,799	$6,576

*At the end of 2004, assets of discontinued operations included cash of $2.5 million.

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands, except share data)

	December 31	
	2007	2006
ASSETS		
Utility plant		
Utility plant, at original cost	**$538,229**	$517,816
Less accumulated depreciation	**235,465**	226,018
Utility plant, at original cost, net of accumulated depreciation	**302,764**	291,798
Property under capital leases, net	**6,788**	7,485
Construction work-in-progress	**9,611**	8,496
Nuclear fuel, net	**1,105**	1,017
Total utility plant, net	**320,268**	308,796
Investments and other assets		
Investments in affiliates	**93,452**	39,339
Non-utility property, less accumulated depreciation ($3,681 in 2007 and $4,048 in 2006)	**1,646**	1,640
Millstone decommissioning trust fund	**5,645**	5,476
Other	**7,504**	7,120
Total investments and other assets	**108,247**	53,575
Current assets		
Cash and cash equivalents	**3,803**	2,799
Restricted cash	**62**	3,081
Special deposits	**1,000**	1,500
Accounts receivable, less allowance for uncollectible accounts ($1,751 in 2007 and $1,707 in 2006)	**24,086**	27,042
Accounts receivable - affiliates, less allowance for uncollectible accounts ($48 in 2007 and $48 in 2006)	**254**	73
Unbilled revenues	**17,665**	16,654
Materials and supplies, at average cost	**5,461**	5,298
Prepayments	**8,942**	7,389
Deferred income taxes	**3,638**	2,899
Assets held for sale	**-**	386
Other current assets	**1,788**	1,446
Total current assets	**66,699**	68,567
Deferred charges and other assets		
Regulatory assets	**31,988**	52,179
Other deferred charges - regulatory	**8,988**	12,127
Other deferred charges and other assets	**4,124**	5,694
Total deferred charges and other assets	**45,100**	70,000
TOTAL ASSETS	**$540,314**	$500,938

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands, except share data)

	December 31	
	2007	2006
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 12,474,687 issued and 10,244,559 outstanding at December 31, 2007 and 12,382,801 issued and 10,132,826 outstanding at December 31, 2006	**$74,848**	$74,297
Other paid-in capital	**56,324**	54,225
Accumulated other comprehensive loss	**(378)**	(544)
Treasury stock, at cost, 2,230,128 shares at December 31, 2007 and 2,249,975 shares at December 31, 2006	**(50,734)**	(51,186)
Retained earnings	**108,747**	102,560
Total common stock equity	**188,807**	179,352
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Preferred stock subject to mandatory redemption	**2,000**	3,000
Long-term debt	**112,950**	115,950
Capital lease obligations	**5,889**	6,612
Total capitalization	**317,700**	312,968
Current liabilities		
Current portion of preferred stock subject to mandatory redemption	**1,000**	1,000
Current portion of long-term debt	**3,000**	-
Accounts payable	**6,253**	6,382
Accounts payable - affiliates	**13,205**	12,022
Notes payable	**63,800**	10,800
Nuclear decommissioning costs	**2,309**	2,737
Power contract derivatives	**3,225**	1,554
Other current liabilities	**20,761**	20,336
Total current liabilities	**113,553**	54,831
Deferred credits and other liabilities		
Deferred income taxes	**33,666**	32,467
Deferred investment tax credits	**3,341**	3,720
Nuclear decommissioning costs	**9,580**	12,166
Asset retirement obligations	**3,200**	3,041
Accrued pension and benefit obligations	**19,874**	37,547
Power contract derivatives	**4,592**	6,443
Other deferred credits - regulatory	**9,395**	12,687
Other deferred credits and other liabilities	**25,413**	25,068
Total deferred credits and other liabilities	**109,061**	133,139
Commitments and contingencies		
TOTAL CAPITALIZATION AND LIABILITIES	**$540,314**	$500,938

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

.CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED STATEMENT OF CHANGES IN COMMON STOCK EQUITY
(dollars in thousands, except share data)

	Common Stock					Treasury Stock			
	Shares Issued	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Loss	Deferred Compensation	Share	Amount	Retained Earnings	Total
Balance, December 31, 2004	12,193,093	$73,153	$51,964	$(130)	$(36)	-	$-	$99,702	$224,653
Net Income								6,346	6,346
Other comprehensive loss				(284)					(284)
Common stock issuance:									
Stock compensation plans	37,320	224	606						830
Dividend reinvestment plan	41,822	251	660						911
Allocation of benefits - performance and restricted plans			(752)						(752)
Amortization of benefits performance plans			(123)						(123)
Amortization of benefits restricted plans	11,170	67	133		31				231
Dividends declared:									
Common - $1.15 per share								(14,099)	(14,099)
Cumulative non-redeemable preferred stock								(368)	(368)
Amortization of preferred stock issuance expenses			25						25
Balance, December 31, 2005	12,283,405	$73,695	$52,513	$(414)	$(5)	-	$-	$91,581	$217,370
Net income								18,352	18,352
Other comprehensive income				305					305
Adjustment to initially apply SFAS No. 158, net of tax				(435)					(435)
Common stock reacquired						2,249,975	(51,186)		(51,186)
Stock options exercised	79,335	476	920						1,396
Share-based compensation:									
Common and nonvested shares	20,061	126	295						421
Performance share plans			473		5				478
Dividends declared:									
Common - $0.69 per share								(6,971)	(6,971)
Cumulative non-redeemable preferred stock								(368)	(368)
Amortization of preferred stock issuance expenses			17						17
Loss on reacquisition of capital stock			7					(34)	(27)
Balance, December 31, 2006	12,382,801	$74,297	$54,225	$(544)	$-	2,249,975	$(51,186)	$102,560	$179,352
Cumulative effect of adoption of FIN 48								120	120
Adjusted balance at January 1, 2007	12,382,801	$74,297	$54,225	$(544)	$-	2,249,975	$(51,186)	$102,680	$179,472
Net income								15,804	15,804
Other comprehensive income				166					166
Dividend reinvestment plan	9,721	58	475			(19,847)	452		985
Stock options exercised	75,775	455	1,097						1,552
Share-based compensation:									
Common and nonvested shares	6,390	38	174						212
Performance share plans			333						333
Dividends declared:									
Common - $0.92 per share								(9,366)	(9,366)
Cumulative non-redeemable preferred stock								(368)	(368)
Amortization of preferred stock issuance expenses			17						17
Loss on reacquisition of capital stock			3					(3)	-
Balance, December 31, 2007	12,474,687	$74,848	$56,324	$(378)	$-	2,230,128	$(50,734)	$108,747	$188,807

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General Description of Business Central Vermont Public Service Corporation ("we", "us", "CVPS" or the "company") is engaged in the purchase, production, transmission, distribution and sale of electricity. We are the largest electric utility in Vermont, serving about 158,000 retail customers in nearly two-thirds of the towns, villages and cities in Vermont. Our wholly owned subsidiaries include Custom Investment Corporation, C.V. Realty, Inc., Central Vermont Public Service Corporation - East Barnet Hydroelectric, Inc. ("East Barnet") and Catamount Resources Corporation ("CRC").

We have equity ownership interests in Vermont Yankee Nuclear Power Corporation ("VYNPC"), Vermont Electric Power Company, Inc. ("VELCO"), Vermont Transco LLC ("Transco"), Maine Yankee Atomic Power Company ("Maine Yankee"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and Yankee Atomic Electric Company ("Yankee Atomic").

Financial Statement Presentation The focus of the Consolidated Statements of Income is on the regulatory treatment of revenues and expenses as opposed to other enterprises where the focus is on income from continuing operations. Operating revenues and expenses (including related income taxes) are those items that ordinarily are included in the determination of revenue requirements or amounts recoverable from customers in rates. Operating expenses represent the costs of rendering service to be covered by revenue, before coverage of interest and other capital costs. Other income and deductions include nonutility operating results, certain expenses judged not to be recoverable through rates, related income taxes and costs (i.e. interest expense) that utility operating income is intended to cover through the allowed rate of return on equity rather than as a direct cost-of-service revenue requirement.

The focus of the Consolidated Balance Sheets is on utility plant and capital because of the capital-intensive nature of the regulated utility business. The prominent position given to utility plant, capital stock, retained earnings and long-term debt supports regulated ratemaking concepts in that utility plant is the rate base and capitalization (including long-term debt) is the basis for determining the rate of return that is applied to the rate base.

Basis of Consolidation The accompanying consolidated financial statements include the accounts of the company and its subsidiaries in which it has a controlling interest. Inter-company transactions have been eliminated in consolidation. Jointly owned generation and transmission facilities are accounted for on a proportionate consolidated basis using our ownership interest in each facility. Our share of the assets, liabilities and operating expenses of each facility are included in the corresponding accounts on the accompanying consolidated financial statements.

Investments in entities over which we do not maintain a controlling financial interest are accounted for using the equity method when we have the ability to exercise significant influence over their operations. Under this method, we record our ownership share of the net income or loss of each investment in our consolidated financial statements. We have concluded that consolidation of these investments is not required under the provisions of FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities*, as revised ("FIN 46R"). See Note 3 - Investments in Affiliates.

Variable Interest Entities The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Transco and VYNPC are variable interest entities; however, we are not the primary beneficiary of these entities. Our maximum exposure to loss is the amount of our equity investments in Transco and VYNPC. See Note 3 - Investments in Affiliates.

Use of Estimates The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities, and revenues and expenses. Actual results could differ from those estimates. In our opinion, areas where significant judgment is exercised include the valuation of unbilled revenue, pension plan assumptions, nuclear plant decommissioning liabilities, environmental remediation costs, regulatory assets and liabilities, and derivative contract valuations.

Regulatory Accounting Our utility operations are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility and Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. As such, we prepare our financial statements in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"). The application of SFAS No. 71 results in differences in the timing of recognition of certain expenses from those of other businesses and industries. In order for us to report our results under SFAS No. 71, our rates must be designed to recover our costs of providing service, and we 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 our regulated operations. In the event we determine that we no longer meet the criteria for applying SFAS No. 71, the accounting impact would be an extraordinary non-cash charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, we believe future recovery of our regulatory assets is probable. Criteria that could give rise to the discontinuance of SFAS No. 71 include: 1) increasing competition that restricts a 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. In the event that we no longer meet the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, the impact would, among other things, result in an extraordinary charge to operations of $16.9 million pre-tax at December 31, 2007. See Note 7 - Retail Rates and Regulatory Accounting for additional information.

Unregulated Business Our non-regulated business, operated by Eversant Corporation ("Eversant"), a subsidiary of CRC, is SmartEnergy Water Heating Services, Inc., a water heater rental business operating in portions of Vermont and New Hampshire. Results of operations of Eversant and CRC are included in Other Income and Other Deductions on the Consolidated Statements of Income.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes ("SFAS No. 109")*, we recognize deferred tax assets and liabilities for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the tax rate expected to be in effect when the differences are expected to reverse. Investment tax credits associated with utility plant are deferred and amortized ratably to income over the lives of the related properties. We record a valuation allowance for deferred tax assets if we determine that it is more likely than not that such tax assets will not be realized.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109* ("FIN 48"). FIN 48 clarifies the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. We adopted FIN 48 on January 1, 2007 as required. Upon adoption and in accordance with FIN 48, we recognized the cumulative effect of approximately $0.1 million as an increase in the beginning balance of retained earnings related to a decrease in the liability for unrecognized tax benefits. A reconciliation of the beginning and ending amount of gross unrecognized tax benefits follows (dollars in thousands):

Balance at January 1, 2007	$669
Reductions from lapse of the statute of limitations	(39)
Gross amount of increase as a result of current year tax positions	1,240
Balance at December 31, 2007	$1,870

At December 31, 2007 we had $0.4 million of unrecognized tax benefits that would affect the effective tax rate if recognized. During the year we determined that we would file amended returns related to the 2003 - 2006 tax years and increased unrecognized tax benefits by an additional $1.4 million. The unrecognized tax benefits established for the amended returns were subsequently reduced by $0.2 million during the third and fourth quarters of 2007 due to a true-up of the benefits previously recorded with the filed returns as well as part of the uncertainty of the tax position becoming certain via the passage of time. Because of the impact of deferred tax accounting, the disallowance of this item would not affect the effective tax rate.

We recognize interest related to unrecognized tax benefits as interest expense and penalties as other deductions. Accrued interest related to unrecognized tax benefits amounted to less than $0.1 million as of December 31, 2007 and reflects the current year net interest expense on the Consolidated Statement of Income, which was less than $0.1 million. The tax years 2003 - 2006 remain open to examination by major taxing jurisdictions, which include the Internal Revenue Service and the states of New York, New Hampshire, Maine, Connecticut, Pennsylvania, Idaho, Virginia and Vermont. The Internal Revenue Service is currently examining the 2003, 2004 and 2005 tax years and there are no proposed audit adjustments. Tax positions that are likely to reduce unrecognized tax benefits within 12 months of the reporting date are immaterial.

Revenue Recognition Revenues from the sale of electricity to retail customers are recorded when service is rendered or electricity is distributed. These are based on monthly meter readings, and estimates are made to accrue unbilled revenue at the end of each accounting period. We record contractual or firm wholesale sales in the month that power is delivered. We also engage in hourly sales and purchases in the wholesale markets administered by the New England Independent System Operator ("ISO-New England") through the normal settlement process. On a monthly basis, we aggregate these hourly sales and hourly purchases and report them as operating revenue and operating expenses.

Purchased Power We record the cost of power obtained under long-term contracts as operating expenses. These contracts do not convey to us the right to use the related property, plant or equipment. We engage in short-term purchases with other third parties and record them as operating expenses in the month the power is delivered. We also engage in hourly purchases through ISO-New England's normal settlement process. These are included in operating expenses.

Valuation of Long-Lived Assets We periodically evaluate the carrying value of long-lived assets, including our investments in nuclear generating companies, our unregulated investments, and our interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. No impairments of long-lived assets were recorded in 2007 or 2006.

Utility Plant Utility plant is recorded at original cost. Replacements of retirement units of property are charged to utility plant. Maintenance and repairs, including replacements not qualifying as retirement units of property, are charged to maintenance expense. The costs of renewals and improvements of property units are capitalized. The original cost of units retired, net of salvage value, are charged to accumulated provision for depreciation. The primary components of utility plant at December 31 follow (dollars in thousands):

	2007	2006
Wholly owned electric plant in service:		
Distribution	**$288,548**	$275,457
Hydro facilities	**47,759**	46,488
Transmission	**43,230**	41,280
General	**33,572**	33,312
Intangible plant	**6,776**	3,574
Other	**4,576**	4,303
Sub-total wholly owned electric plant in service	**424,461**	404,414
Jointly owned generation and transmission units	**110,830**	110,496
Completed construction	**2,895**	2,863
Held for future use	**43**	43
Utility plant, at original cost	**538,229**	517,816
Accumulated depreciation	**(235,465)**	(226,018)
Property under capital leases, net	**6,788**	7,485
Construction work-in-progress	**9,611**	8,496
Nuclear fuel, net	**1,105**	1,017
Total Utility Plant, net	**$320,268**	$308,796

Property Under Capital Leases We record our commitments with respect to the Hydro-Quebec Phase I and II transmission facilities, and other equipment, as capital leases. At December 31, 2007 Property under Capital Leases was comprised of $24.4 million of original cost less $17.6 million of accumulated amortization. At December 31, 2006 Property under Capital Leases was comprised of $24.2 million of original cost less $16.7 million of accumulated amortization. See Note 16 - Commitments and Contingencies.

Depreciation We use the straight-line remaining life method of depreciation. The total composite depreciation rate was 2.89 percent of the cost of depreciable utility plant in 2007, 3.19 percent in 2006 and 3.18 percent in 2005.

Allowance for Funds During Construction Allowance for funds during construction ("AFUDC") is a non-cash item that is included in the cost of utility plant and represents the cost of borrowed and equity funds used to finance construction. Our AFUDC rates were 8.6 percent in 2007, 8.4 percent in 2006 and 8.4 percent in 2005. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense on the Consolidated Statements of Income. The cost of equity funds is recorded as other income on the Consolidated Statements of Income.

Asset Retirement Obligations Changes to asset retirement obligations on the Consolidated Balance Sheets follow (dollars in thousands):

	2007	2006
Asset retirement obligations at January 1	**$3,041**	$4,059
Revisions in estimated cash flows	**(2)**	(1,184)
Accretion	**235**	178
Liabilities settled during the period	**(74)**	(12)
Asset retirement obligations at December 31	**$3,200**	$3,041

We have legal retirement obligations for decommissioning related to our joint-owned nuclear plant, Millstone Unit #3, and have an external trust fund dedicated to funding our share of future costs. The year-end aggregate fair value of the trust fund was $5.6 million in 2007 and $5.5 million in 2006, and is included in Investments and Other Assets on the Consolidated Balance Sheets.

We consider our past practices, industry practices, management's intent and the estimated economic lives of the assets in determining whether conditional asset retirement obligations can be reasonably estimated. Asset retirement obligations are recognized for items that can be reasonably estimated such as asbestos removal, disposal of polychlorinated biphenyls in certain transformers and breakers, and mercury in batteries and certain meters. We have not recorded an asset retirement obligation associated with asbestos abatement at certain of our sites because the range of time over which we may settle these obligations is unknown and cannot be reasonably estimated.

Non-legal Removal Costs: Our regulated operations collect removal costs in rates for certain utility plant assets that do not have associated legal asset retirement obligations. Non-legal removal costs of about $9.0 million in 2007 and $8.5 million in 2006 are included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Environmental Liabilities We are engaged in various operations and activities that subject us to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. Our policy is to accrue a liability for those sites where costs for remediation, monitoring and other future activities are probable and can be reasonably estimated. See Note 16 - Commitments and Contingencies.

Derivative Financial Instruments We account for certain power contracts as derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted and SFAS No. 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities*, (collectively "SFAS No. 133"). These statements require that derivatives be recorded on the balance sheet at fair value. At December 31, 2007, our power contracts that are derivatives included: 1) one long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice ("Hydro-Quebec Sellback #3"); 2) seven forward sale contracts of various durations; and 3) one long-term forward purchase contract. At December 31, 2006, our power contracts that are derivatives included: 1) Hydro-Quebec Sellback #3; 2) one long-term forward sale contract; and 3) one short-term forward purchase contract. We enter into forward sale contracts to reduce price volatility, since our long-term power forecasts show energy purchases and production in excess of load requirements. We enter into forward purchase contracts for replacement energy during Vermont Yankee scheduled refueling outages.

The estimated fair values of power contract derivatives are based on over-the-counter quotes or broker quotes at the end of the reporting period, except for Hydro-Quebec Sellback #3, which is valued using a binomial tree model and quoted market data when available, along with appropriate valuation methodologies. At December 31, 2007, the estimated fair value of three of the nine power contract derivatives was an unrealized loss of $7.8 million and the estimated fair value of the remaining six was an unrealized gain of $0.7 million, for a net unrealized loss of $7.1 million. At December 31, 2006, the estimated fair value of all power contract derivatives was an unrealized loss of $8.0 million.

We are able to economically hedge our exposure to congestion charges that result from constraints on the transmission system with Financial Transmission Rights ("FTRs"). FTRs are awarded to the successful bidders in periodic auctions administered by ISO-New England, in which we participate. We have determined that FTRs are derivatives. The estimated fair value of FTRs that we held at December 31, 2007 and December 31, 2006 was zero since their auction clearing prices approximated fair value. We account for FTRs in the month that they settle in ISO-New England; these are included in Purchased Power on the Consolidated Statements of Income.

Based on a PSB-approved Accounting Order, we record the changes in fair value of power contract derivatives as deferred charges or deferred credits on the balance sheet, depending on whether the fair value is an unrealized loss or gain. The corresponding offsets are recorded as current and long-term assets or liabilities depending on the duration.

Share-Based Compensation We adopted SFAS No. 123R, *Share-Based Payment* ("SFAS No. 123R"), on January 1, 2006, as required. SFAS No. 123R replaced SFAS No. 123, *Accounting for Stock-Based Compensation,* and superseded APB Opinion No. 25, *Accounting for Stock Issued to Employees.* We elected the modified prospective method, so prior periods are not revised. Under SFAS No. 123R, share-based compensation costs are measured at the grant date based on the fair value of the award and recognized as expense on a straight-line basis over the requisite service period. We had previously accounted for share-based compensation costs under APB No. 25 and related guidance. No compensation expense was recognized for stock options granted in periods prior to January 1, 2006 because they were granted at the market value of the underlying shares on the date of grant. See Note 8 - Share-Based Compensation.

The table below illustrates the effect on net income and earnings per share as if the fair value method had been applied to all stock-based compensation, prior to adoption of SFAS No. 123R (dollars in thousands, except per share amounts).

	2005
Earnings available for common stock, as reported	$5,978
Add: Share-based compensation expense included in reported net income, net of tax	62
Deduct: Share-based compensation expense under fair value method, net of tax	(192)
Pro forma net income	$5,848
Earnings per share:	
Basic - as reported	$0.49
Basic - pro forma	$0.48
Diluted - as reported	$0.48
Diluted - pro forma	$0.47

Pension and Benefits Our defined benefit pension plans and postretirement welfare benefit plans are accounted for in accordance with FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158") and FASB Staff Position ("FSP") FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. We use the fair value method to value all asset classes included in our pension and postretirement medical benefit trust funds. See Note 14 - Pension and Postretirement Medical Benefits for more information. Also see Recent Accounting Pronouncements below.

Accumulated Other Comprehensive Loss ("AOCL") The after-tax components of accumulated other comprehensive loss on the Consolidated Balance Sheets at December 31 follows (dollars in thousands):

	Pension and Other Benefits	**Unrealized Losses on Available-for-sale Securities**	**AOCL After-tax**
Balance at December 31, 2005	**$(394)**	**$(20)**	**$(414)**
Additional minimum pension liability, net	394	-	394
Adoption of SFAS 158	(544)	-	(544)
Loss on investments	-	20	20
Balance at December 31, 2006	**$(544)**	**$ -**	**$(544)**
Pension and postretirement medical benefit costs, net	166	-	166
Balance at December 31, 2007	**$(378)**	**$ -**	**$(378)**

Cash and Cash Equivalents We consider all liquid investments with an original maturity of three months or less when acquired to be cash and cash equivalents. Cash and cash equivalents consist primarily of cash in banks and money market funds.

Restricted Cash Restricted cash includes funds held by ISO-New England for performance assurance requirements described in Note 16 - Commitments and Contingencies.

Special Deposits Special deposits include mandatory sinking fund payments of $1.0 million in 2007 and in 2006 for our preferred stock subject to mandatory redemption. In 2006 it also included collateral payments we make under performance assurance requirements for certain power contracts as described in Note 16 - Commitments and Contingencies.

Supplemental Financial Statement Data Supplemental financial information for the accompanying financial statements is provided below.

Other Income: The components of Other income on the Consolidated Statements of Income for the years ended December 31 follow (dollars in thousands):

	2007	2006	2005
Interest on temporary investments	**$273**	$1,603	$1,311
Non-utility revenue and non-operating rental income	**1,842**	1,878	1,932
Amortization of contributions in aid of construction - tax adder	**951**	888	843
Other interest and dividends	**372**	511	584
Regulatory asset carrying costs	**-**	-	(653)
Gain on sale of non-utility property	**105**	317	12
Miscellaneous other income	**270**	290	92
Total	**$3,813**	$5,487	$4,121

Other Deductions: The components of Other deductions on the Consolidated Statements of Income for the years ended December 31 follow (dollars in thousands):

	2007	2006	2005
Supplemental retirement benefits and insurance	**$785**	$568	$709
Non-utility expenses	**1,183**	1,281	1,226
Realized losses on available-for-sale securities	**-**	151	573
Vermont Yankee fuel rod disallowance - 2005 Rate Order	**-**	-	403
Miscellaneous other deductions	**513**	401	641
Total	**$2,481**	$2,401	$3,552

Other Current Liabilities: The components of Other current liabilities on the Consolidated Balance Sheets at December 31 follow (dollars in thousands):

	2007	2006
Deferred compensation plans and other	**$2,655**	$2,889
Accrued employee-related costs	**4,367**	4,136
Other taxes and Energy Efficiency Utility	**3,264**	3,169
Cash concentration account - outstanding checks	**740**	1,332
Obligation under capital leases	**899**	873
Miscellaneous accruals	**8,836**	7,937
Total	**$20,761**	$20,336

Other Deferred Credits and Other Liabilities: The components of Other deferred credits and other liabilities on the Consolidated Balance Sheets at December 31 follow (dollars in thousands):

	2007	2006
Environmental reserve	**$1,097**	$1,752
Non-legal removal costs	**8,990**	8,474
Contribution in aid of construction - tax adder	**5,423**	5,229
Reserve for loss on power contract	**8,371**	9,567
Accrued income taxes	**718**	-
Provision for rate refund	**778**	-
Other	**36**	46
Total	**$25,413**	$25,068

Dividends Declared Per Share of Common Stock: The timing of common stock dividend declarations fluctuates whereas the dividend payments are made on a quarterly basis. In 2007, we declared and paid cash dividends of 92 cents per share of common stock. In 2006, we declared cash dividends of 69 cents per share of common stock, and paid cash dividends of 92 cents per share. In 2005, we declared cash dividends of $1.15 per share and paid cash dividends of 92 cents per share of common stock.

Supplemental Cash Flow Information: Cash paid for interest and income tax as of December 31 follows (dollars in thousands):

	2007	2006	2005
Interest (net of amounts capitalized)	**$8,073**	$8,109	$8,886
Income taxes (net of refunds)	**$6,162**	$6,300	$6,086

Construction and plant expenditures on the Consolidated Statements of Cash Flows reflect actual payments made during the periods. Construction and plant-related expenditures are accrued at the end of each reporting period. At December 31, 2007, $0.9 million of construction and plant-related accruals were included in Accounts Payable, and $0.3 million was included in Other Current Liabilities. At December 31, 2006, $0.5 million of construction and plant-related accruals were included in Accounts Payable, and $0.4 million was included in Other Current Liabilities.

We maintain a cash concentration account for payments related to our routine business activities. The book overdraft amount resulting from outstanding checks is recorded as a current liability at the end of each reporting period. Changes in the book overdraft position are reflected in operating activities on the Consolidated Statements of Cash Flows.

Reclassifications Certain prior year amounts have been reclassified to conform to the current year presentation. In 2005, $57.9 million of proceeds received from the sale of discontinued operations, net of transaction costs, was reported on the Consolidated Statement of Cash Flows. In 2007, we changed our presentation of the sale proceeds from investing activities of continued operations to investing activities of discontinued operations to better reflect the cash flows from continuing operations under SFAS No. 95, *Statement of Cash Flows*. The following Change in Presentation table provides a reconciliation of amounts as originally reported to amounts as reclassified on the 2005 Consolidated Statement of Cash Flows.

	As Originally Reported	**Reclassification Amounts**	**As Reclassified**
INVESTING ACTIVITIES			
Proceeds from sales of discontinued operations, net of transaction costs	$57,914	$(57,914)	$-
Net cash (used for) provided by investing activities of continuing operations	6,102	(57,914)	(51,812)
DISCONTINUED OPERATIONS			
Net cash provided by investing activities (includes proceeds from sales of discontinued operations, net of transaction costs)	$(11,972)	$57,914	$45,942
Net cash provided by discontinued operations	(2,495)	57,914	55,419

Recent Accounting Pronouncements
SFAS No. 157: In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("SFAS No. 157"), which addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under U.S. GAAP. While the standard does not expand the use of fair value in any new circumstances, it has applicability to several current accounting standards that require or permit us to measure assets and liabilities at fair value.

SFAS No. 157 is effective for most fair value measurements, other than leases and certain non-financial assets and liabilities, beginning January 1, 2008. SFAS No. 157 defines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date," or the "exit price." Accordingly, we must determine that fair value of an asset or liability based on the assumptions that market participants would use in pricing the asset or liability (if available), and not our assumptions. The identification of market participant assumptions provides a basis for determining what inputs are to be used for pricing each asset or liability. SFAS 157 also establishes a three-level fair value hierarchy, reflecting the extent to which inputs to the determination of fair value can be observed, and requires fair value disclosures based upon this hierarchy. We will include these disclosures in the Notes to our Condensed Consolidated Financial Statements subsequent to the adoption of SFAS No. 157. We do not currently expect that the adoption of SFAS No. 157 will have a material impact on our financial position, results of operations and cash flows.

SFAS No. 158: We adopted the recognition and disclosure provisions of SFAS No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158") as of December 31, 2006. SFAS No. 158 requires companies to measure plan assets and benefit obligations as of the same date as their fiscal year-end balance sheet. This provision of SFAS No. 158 is effective for CVPS in 2008. We estimate that changing the annual benefit measurement date from September 30 to December 31 will result in a pre-tax charge of $1.4 million, of which $0.1 million will be recorded to retained earnings. In the most recent retail rate proceeding we received approval for recovery of the regulated utility portion of the impact resulting from the change in measurement date. Accordingly, we will record a regulatory asset of approximately $1.3 million in the first quarter of 2008 that will be amortized over five years.

SFAS No. 159: In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* ("SFAS No. 159"). SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007 (beginning January 1, 2008 for CVPS). We do not expect that the adoption of SFAS No. 159 will materially impact our financial position, results of operations or cash flows.

EITF 06-04 and EITF 06-10: In September 2006, the FASB issued EITF Issue 06-04, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split Dollar Life Insurance Arrangements,* ("EITF 06-04"). EITF 06-04 requires employers to record a liability for future benefits for endorsement split-dollar life insurance arrangements that provide a postretirement benefit to an employee. In March 2007, the FASB issued EITF 06-10, *Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements* ("EITF 06-10"). EITF 06-10 defines whether an entity should record a liability for the postretirement benefit associated with a collateral assignment split-dollar life insurance arrangement and how an employer should recognize and measure the related asset. Both EITF issues become effective for fiscal periods beginning after December 15, 2007. We do not expect that these EITF issues will materially impact our financial position, results of operations or cash flows.

SFAS No. 141(R): In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS No. 141(R)"). SFAS No. 141(R) replaces SFAS No. 141 and establishes principles and requirements for the recognition and measurement by acquirers of assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and any goodwill acquired. SFAS No. 141(R) also establishes disclosure requirements to enable financial statement readers to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective as of the beginning of an entity's fiscal year that begins on or after December 15, 2008 (beginning January 1, 2009 for CVPS). The impact of applying SFAS No. 141(R) for periods subsequent to implementation will be dependent upon the nature of any transactions within the scope of SFAS No. 141(R).

SFAS No. 160: In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51* ("SFAS No. 160"). SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS No. 160 also established reporting requirements that provide sufficient disclosures that identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. It requires that once a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary be initially measured at fair value. SFAS No. 160 is effective as of the beginning of an entity's first fiscal year beginning on or after December 15, 2008 (beginning January 1, 2009 for CVPS). We have not yet evaluated the impact, if any, that the adoption of SFAS No. 160 may have on our financial statements.

NOTE 2 - EARNINGS PER SHARE ("EPS")
The Consolidated Statements of Income include basic and diluted per share information. Basic EPS is calculated by dividing net income, after preferred dividends, by the weighted-average common shares outstanding for the period. Diluted EPS follows a similar calculation except that the weighted-average common shares are increased by the number of potentially dilutive common shares. The table below provides a reconciliation of the numerator and denominator used in calculating basic and diluted EPS for the years ended December 31 (dollars in thousands, except share information):

	2007	2006	2005
Numerator for basic and diluted EPS:			
Income from continuing operations	$15,804	$18,101	$1,410
Dividends declared on preferred stock	368	368	368
Net income from continuing operations available for common stock	$15,436	$17,733	$1,042
Denominators for basic and diluted EPS:			
Weighted-average basic shares of common stock outstanding	10,185,930	10,756,027	12,258,508
Dilutive effect of stock options	132,302	66,971	106,119
Dilutive effect of performance shares	31,959	4,184	1,688
Weighted-average diluted shares of common stock outstanding	10,350,191	10,827,182	12,366,315

All outstanding stock options were included in the computation of diluted shares in 2007 because the exercise prices were below the average market price of the common shares. Outstanding stock options totaling 60,077 in 2006 and 192,764 in 2005 were excluded from the computation because the exercise prices were above the average market price of the common shares.

NOTE 3 - INVESTMENTS IN AFFILIATES
Our equity method investments and equity in earnings from those investments follow (dollars in thousands):

		Investment At December 31		**Equity in Earnings As of December 31**		
	Direct Ownership	**2007**	2006	**2007**	2006	2005
Vermont Electric Power Company, Inc.:						
Common stock	47.05%	**$11,257**	$11,247			
Preferred stock	48.03%	**277**	188			
Subtotal		**11,534**	11,435	**$1,404**	$1,324	$1,389
Vermont Transco LLC (a)	39.79%	**78,784**	24,430	**4,482**	1,500	-
Vermont Yankee Nuclear Power Corporation	58.85%	**2,804**	2,825	**431**	441	388
Connecticut Yankee Atomic Power Company	2.00%	**250**	276	**94**	(61)	54
Maine Yankee Atomic Power Company	2.00%	**29**	332	**8**	31	41
Yankee Atomic Electric Company	3.50%	**51**	41	**11**	5	(3)
Total Investments in Affiliates		**$93,452**	$39,339	**$6,430**	$3,240	$1,869

(a) Ownership percentage was 29.86 percent at December 31, 2006.

Undistributed earnings of these affiliates, included in Retained Earnings on our Consolidated Balance Sheets, amounted to $2.9 million at December 31, 2007 and $1.4 million at December 31, 2006. Of these amounts, $2.5 million at December 31, 2007 and $1.1 million at December 31, 2006 were from our investment in Transco.

VELCO and Transco VELCO, through its wholly owned subsidiary, Vermont Electric Transmission Company, Inc., and Transco own and operate an integrated transmission system in Vermont over which bulk power is delivered to all electric utilities in the state. Transco, a Vermont limited liability company, was formed by VELCO and its owners. In June 2006, VELCO transferred its assets to Transco in exchange for 2.4 million Class A Units, and Transco assumed all of VELCO's debt. VELCO and its employees now manage the operations of Transco under a Management Services Agreement between VELCO and Transco. Transco operates under an Operating Agreement among us, VELCO, Transco, Green Mountain Power and most of the other Vermont electric utilities. Transco also operates under the Amended and Restated Three Party Agreements, assigned to Transco from VELCO, among us, Green Mountain Power, VELCO and Transco.

We invested $53.0 million in Transco in 2007 and $23.3 million in 2006. Our direct ownership interest was 39.79 percent at December 31, 2007 and at December 31, 2006 was 29.86 percent. Our ownership interest in Transco is represented by Class A Units that receive a return on equity investments of 11.5 percent under the 1991 Transmission Agreement ("VTA"). At December 31, 2007, our total direct and indirect interest in Transco was 45.68 percent. It was 44.34 percent at December 31, 2006. Transco is a variable interest entity; but we are not the primary beneficiary.

Cash dividends received were $1.3 million in 2007 and 2006. VELCO's consolidated revenues shown in the table below include sales to us of $2.7 million in 2006 and 2005. They also include Transco's billings to us of $5.1 million in 2007 and a net credit of $1.5 million in 2006. These amounts are included in Transmission - affiliates on our Consolidated Statements of Income. Accounts payable to VELCO were $5.7 million at December 31, 2007 and $5.4 million at December 31, 2006.

VELCO's summarized consolidated financial information (including Transco) at December 31 follows (dollars in thousands):

	2007	2006	2005
Operating revenues	**$51,911**	$35,808	$31,119
Operating income	**$21,922**	$13,467	$9,938
Income before non-controlling interest and income tax	**$13,955**	$8,000	$4,791
Less members' non-controlling interest in income	**9,483**	3,245	-
Less income tax	**1,661**	1,888	1,773
Net income	**$2,811**	$2,867	$3,018

	2007	2006
Current assets	**$50,467**	$31,805
Non-current assets	**395,923**	279,320
Total assets	**446,390**	311,125
Less:		
Current liabilities	**34,384**	96,598
Non-current liabilities	**215,014**	133,695
Members' non-controlling interest	**172,592**	56,469
Net assets	**$24,400**	$24,363

Transco's summarized financial information (included above in VELCO's summarized consolidated financial information) for 2007 and 2006 (from inception at June 30 to December 31) follows (dollars in thousands).

	2007	2006
Operating revenues	**$51,466**	$18,330
Operating income	**$21,922**	$7,950
Net income	**$13,904**	$5,527

	2007	2006
Current assets	**$39,354**	$19,084
Non-current assets	**389,351**	275,114
Total assets	**$428,705**	$294,198
Less:		
Current liabilities	**$21,120**	$82,146
Non-current liabilities	**209,383**	130,425
Net assets	**$198,202**	$81,627

Transmission services provided by Transco are billed to us under the VTA. All Vermont electric utilities are parties to the VTA. In June 2007, FERC issued an Order combining three FERC filings related to the VTA, including a request by five municipal utilities for FERC approval to withdraw from the VTA and take transmission service under a different tariff, and requests by Transco for revisions to the VTA. In January 2008, the parties reached a preliminary settlement agreement that would resolve all issues that were raised in the FERC proceeding. In the event a definitive settlement agreement is not filed by April 1, 2008, a schedule for hearings would be determined.

Transco's billings to us primarily include the VTA and charges and reimbursements under the NEPOOL Open Access Transmission Tariff ("NOATT"). Transco's billings to us in 2007 and 2006 are described above. Accounts payable to Transco were $1.8 million at December 31, 2007 and $0.8 million at December 31, 2006. Cash dividends received were $3.1 million in 2007 and $0.4 million in 2006.

VYNPC VYNPC sold its nuclear plant to Entergy Nuclear Vermont Yankee, LLC ("ENVY") in July 2002. The sale agreement included a purchased power contract ("PPA") between VYNPC and ENVY. Under the PPA, VYNPC pays ENVY for generation at fixed rates, and in turn, bills the PPA charges from ENVY with certain residual costs of service through a FERC tariff to the VYNPC sponsors, including us. Our entitlement to energy produced by the Vermont Yankee plant is about 29 percent. See Note 16 - Commitments and Contingencies.

Although we own a majority of the shares of VYNPC, the Power Contracts, Sponsor Agreement and composition of the board of directors, under which it operates, effectively restrict our ability to exercise control over VYNPC. VYNPC is a variable interest entity; but we are not the primary beneficiary.

VYNPC's summarized financial information at December 31 follows (dollars in thousands):

	2007	2006	2005
Operating revenues	**$160,143**	$201,325	$160,613
Operating income (loss)	**$3,130**	$3,513	$(321)
Net income	**$733**	$748	$660

	2007	2006
Current assets	**$31,121**	$28,460
Non-current assets	**135,092**	129,461
Total assets	**166,213**	157,921
Less:		
Current liabilities	**16,325**	15,569
Non-current liabilities	**145,123**	137,551
Net assets	**$4,765**	$4,801

VYNPC's revenues shown in the table above include sales to us of $55.8 million in 2007, $70.1 million in 2006 and $55.7 million in 2005. These amounts are included in Purchased power - affiliates on our Consolidated Statements of Income. Also included in VYNPC's revenues above are sales of $0.3 million each year representing a small portion of our entitlement received by a secondary purchaser. Accounts payable to VYNPC were $5.6 million at December 31, 2007 and $5.5 million at December 31, 2006. Cash dividends received were $0.4 million in 2007 and 2006.

Maine Yankee, Connecticut Yankee and Yankee Atomic We are responsible for paying our ownership percentage of decommissioning and all other costs for Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down. All three collect decommissioning and closure costs through FERC-approved wholesale rates charged under power purchase agreements with us and several other New England utilities. Historically, our share of these costs has been recovered from retail customers through PSB-approved rates. We believe based on historical rate recovery that our share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. However, if the FERC disallows recovery of any of these costs in their wholesale rates, there is a risk that the PSB would disallow recovery of our share in retail rates. Information related to estimated decommissioning and closure costs for each plant based on their most recent FERC-approved rate settlements is shown below (dollars in millions):

	Remaining Obligations	Revenue Requirements	Company Share
Maine Yankee	$130.9	$100.5	$2.0
Connecticut Yankee	$168.8	$350.1	$7.0
Yankee Atomic	$111.5	$82.3	$2.9

The remaining obligations are the estimated remaining decommissioning costs in 2007 dollars for the period 2008 through 2023 for Maine Yankee and Connecticut Yankee and through 2022 for Yankee Atomic. Revenue requirements are the estimated future payments to recover estimated FERC-approved decommissioning and other costs (in nominal dollars) for 2008 through 2010 for Maine Yankee, 2015 for Connecticut Yankee and 2014 for Yankee Atomic. Revenue requirements include Maine Yankee and Connecticut Yankee collections for required contributions to pre-1983 spent fuel funds. Yankee Atomic has already collected and paid these required pre-1983 contributions. These estimates may be revised from time to time based on information available to the company regarding estimated future costs. Our share of the estimated costs shown in the table above are included in regulatory assets and nuclear decommissioning liabilities (current and non-current) on the Consolidated Balance Sheets.

Maine Yankee: Maine Yankee's wholesale rates are currently based on a September 2004 FERC-approved settlement. Our share of decommissioning and other costs amounted to $1.1 million in 2007, $1.3 million in 2006 and $1.2 million in 2005. These are included in Purchased power - affiliates on the Consolidated Statements of Income. Return of capital in the form of common stock redemptions were $0.3 million in 2007 and $0.2 million in 2006.

Plant decommissioning activities were completed in 2005 and the Nuclear Regulatory Commission ("NRC") amended Maine Yankee's operating license in October 2005 for operation of the Independent Spent Fuel Storage Installation. This amendment reduced the size of the licensed property to include only the land immediately around the Independent Spent Fuel Storage Installation. Maine Yankee remains responsible for safe storage of the plant's spent nuclear fuel and waste at the site until the United States Department of Energy ("DOE") meets its obligation to remove the material from the site.

Connecticut Yankee: Connecticut Yankee's wholesale rates are currently based on a 2006 FERC-approved settlement. The notable provisions of the settlement included: 1) reduced decommissioning collections to reflect a lower escalation factor beginning January 1, 2007; 2) resolution of any claims of imprudence made in the docket against Connecticut Yankee in its decommissioning effort with no finding of imprudence; 3) reduced decommissioning collections in 2007 through 2009 to credit ratepayers with a $15.0 million settlement payment from Bechtel Power Corporation; 4) a budget incentive plan to reduce the decommissioning collections by $10.0 million wherein timely license termination performance by Connecticut Yankee would offset some of that amount; 5) an investment earnings tracking mechanism for performance greater than or less than certain targets; and 6) resumption of reasonable payments of dividends by Connecticut Yankee to its stockholders subject to certain incentive target balances.

Our share of decommissioning and other costs amounted to $1.0 million in 2007, $2.4 million in 2006 and 2005. These are included in Purchased power - affiliates on the Consolidated Statements of Income. Dividends from Connecticut Yankee amounted to $0.1 million in 2007 and zero in 2006. Additionally, we received $0.6 million from common stock redemption in 2006, and none in 2007.

Plant decommissioning activities were completed in 2007 and the NRC amended Connecticut Yankee's operating license in November 2007 for operation of the Independent Spent Fuel Storage Installation. This amendment reduced the size of the licensed property to include only the land immediately around the Independent Spent Fuel Storage Installation. Connecticut Yankee remains responsible for safe storage of the plant's spent nuclear fuel and waste at the site until the DOE meets its obligation to remove the material from the site.

Yankee Atomic: Yankee Atomic's wholesale rates are currently based on a 2006 FERC-approved settlement. Based on the approved settlement, Yankee Atomic agreed to reduce its revenue requirements by $79.0 million for the period 2006-2010 and to increase its revenue requirements by $47.0 million for the period 2011-2014. The revision includes adjustments for contingencies, projected escalation and certain decontamination and dismantling expenses. The approved settlement also provides for reconciling and adjusting future charges based on actual decontamination and dismantling expenses and the decommissioning trust fund's actual investment earnings. Our share of decommissioning and other costs amounted to $0.4 million in 2007, $1.7 million in 2006 and $1.9 million in 2005. These are included in Purchased power - affiliates on the Consolidated Statements of Income.

Plant decommissioning activities were completed in 2007 and the NRC amended Yankee Atomic's operating license in August 2007 for operation of the Independent Spent Fuel Storage Installation. This amendment reduced the size of the licensed property to include only the land immediately around the Independent Spent Fuel Storage Installation. Yankee Atomic remains responsible for safe storage of the plant's spent nuclear fuel and waste at the site until the DOE meets its obligation to remove the material from the site.

DOE Litigation: All three companies have been seeking recovery of fuel storage-related costs stemming from the default of the DOE under the 1983 fuel disposal contracts that were mandated by the United States Congress under the Nuclear Waste Policy Act of 1982. Under the Act, the companies believe the DOE was required to begin removing spent nuclear fuel and Greater than Class C material from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel has been collected by the DOE, and spent nuclear fuel is being stored at each of the plants. Maine Yankee, Connecticut Yankee and Yankee Atomic collected the funds from us and other wholesale utility customers, under FERC-approved wholesale rates, and our share of these payments were collected from retail customers.

On September 30, 2006, the United States Court of Federal Claims issued judgment in the spent fuel litigation. Maine Yankee was awarded $75.8 million in damages through 2002, Connecticut Yankee was awarded $34.2 million through 2001 and Yankee Atomic was awarded $32.9 million through 2001. The three companies had claimed actual damages through the same periods in the amounts of $78.1 million for Maine Yankee, $37.7 million for Connecticut Yankee and $60.8 million for Yankee Atomic. On December 4, 2006, the DOE filed a notice of appeal to the United States Court of Appeals for the Federal Circuit ("Appeals Court") in all three cases, and on December 14, 2006, all three companies filed notices of cross appeals.

On February 9, 2007, the Appeals Court issued an order consolidating the three cases. Later in 2007, the Appeals Court issued orders making two other cases companion appeals. Oral arguments on the pending appeals were held in February 2008. Due to the complexity of the issues and the appeals, the three companies cannot predict the amount of damages that will actually be received or the timing of the final determination of such damages. Each of the companies' respective FERC settlements require that damage payments, net of taxes and net of further spent fuel trust funding, be credited to ratepayers including us. We expect that our share of these payments, if any, would be credited to our ratepayers as well.

The Court's decision, if upheld, establishes the DOE's responsibility for reimbursing Maine Yankee for its actual costs through 2002 and Connecticut Yankee and Yankee Atomic for their actual costs through 2001 related to the incremental spent fuel storage, security, construction and other costs of the spent fuel storage installation. Although the decision does not resolve the question regarding damages in subsequent years, the decision does support future claims for the remaining spent fuel storage installation construction costs. In December 2007, Maine Yankee, Connecticut Yankee and Yankee Atomic filed a second round of claims against the government for damages sustained since January 1, 2002 for Connecticut Yankee and Yankee Atomic, and since January 1, 2003 for Maine Yankee. We cannot predict the ultimate outcome of these cases due to the pending appeals and the complexity of the issues in the second round of cases.

NOTE 4 - DISCONTINUED OPERATIONS

On December 20, 2005, CRC completed the sale of Catamount to CEC Wind Acquisition, LLC, a Delaware limited liability company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). We agreed to indemnify Catamount and Diamond Castle, and certain of their respective affiliates, in respect of a breach of certain representations, warranties and covenants as described in Note 16 - Commitments and Contingencies. Cash proceeds from the 2005 sale were $59.25 million, resulting in an after-tax gain of $5.6 million in 2005.

Income from discontinued operations as of December 31 is summarized below (dollars in thousands).

	2007	2006	2005
Operating revenues	**$-**	**$-**	$-
Operating expenses	**-**	**-**	(315)
Operating Income	**-**	**-**	315
Other income and (deductions):			
Equity in earnings of non-utility investments	**-**	**-**	1,591
Gain on sale of non-utility investments	**-**	**-**	-
Other income	**-**	**-**	2,093
Other deductions	**-**	**-**	(4,951)
Benefit for income taxes		**251**	856
Total other income and (deductions)	**-**	**251**	(411)
Total interest expense	**-**	**-**	575
Net income (loss) from discontinued operations	**-**	**251**	(671)
Gain from disposal, net of $5,183 income tax	**-**	**-**	5,607
Income from discontinued operations	**$-**	**$251**	$4,936

NOTE 5 - FINANCIAL INSTRUMENTS

The estimated fair values of financial instruments at December 31 follow (dollars in thousands)

	2007		2006	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Power contract derivatives, net (includes current portion)	**$7,110**	**$7,110**	$7,997	$7,997
Preferred stock not subject to mandatory redemption	**$8,054**	**$4,119**	$8,054	$5,690
Preferred stock subject to mandatory redemption (includes current portion)	**$3,000**	**$2,975**	$4,000	$4,105
Long-term debt:				
First mortgage bonds (includes current portion)	**$110,500**	**$114,279**	$110,500	$114,360
New Hampshire Industrial Development Authority Bonds	**$5,450**	**$5,371**	$5,450	$5,409

The estimated fair values of power contract derivatives are based on over-the-counter quotes or broker quotes at the end of the reporting period, with the exception of one long-term power contract that is valued using a binomial tree model and quoted market data when available, along with appropriate valuation methodologies. In 2007, the fair values were unrealized losses of $7.8 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $0.7 million that were recorded as assets on the Consolidated Balance Sheet. In 2006, the fair values were unrealized losses of $8.0 million that were recorded as liabilities on the Consolidated Balance Sheet.

The fair value of our fixed rate securities is estimated based on quoted market prices for the same or similar issues with similar remaining time to maturity or on current rates offered to us. Fair values are estimated to meet disclosure requirements and do not necessarily represent the amounts at which obligations would be settled.

The table above does not include cash and cash equivalents, restricted cash, special deposits, receivables and payables. The carrying values approximate fair value because of the short maturity of those instruments. Also, the carrying value of notes payable approximates fair value since the rates are adjusted at least monthly.

Concentration Risk Financial instruments that potentially expose us to concentrations of credit risk consist primarily of cash, cash equivalents, special deposits and accounts receivable.

Our accounts receivable are not collateralized. As of December 31, 2007, approximately six percent of total accounts receivable are with wholesale entities engaged in the energy industry. This industry concentration could affect our overall exposure to credit risk, positively or negatively, since customers may be similarly affected by changes in economic, industry or other conditions.

Our practice to mitigate credit risk arising from our energy industry concentration with wholesale entities is to contract with creditworthy power and transmission counterparties or obtain deposits or guarantees from their affiliates. We may also enter into third-party power purchase and sales contracts that require collateral based on credit rating or contain master netting arrangements in the event of nonpayment. Currently, we hold parental guarantees from two transmission customers and from two forward power sale counterparties.

Our material power supply contracts and arrangements are principally with Hydro-Quebec and VYNPC. These contracts comprise the majority of our total energy (mWh) purchases. These supplier concentrations could have a material impact on our power costs, if one or both of these sources were unavailable over an extended period of time. We do not have the ability to seek collateral under these two contracts, but the contracts provide the ability to seek damages for non-performance.

NOTE 6 - INVESTMENT SECURITIES

Millstone Decommissioning Trust Fund We have decommissioning trust fund investments related to our joint-ownership interest in Millstone Unit #3. The decommissioning trust fund was established pursuant to various federal and state guidelines. Among other requirements, the fund is required to be managed by an independent and prudent fund manager. Any gains or losses, realized and unrealized, are expected to be refunded to or collected from ratepayers and are recorded as regulatory assets or liabilities in accordance with SFAS No. 71.

FASB Staff Position Nos. 115-1 and 124-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments,* state that an investment is impaired if the fair value of the investment is less than its cost and if management considers the impairment to be other-than-temporary. We do not have the ability to hold individual securities in the trusts because regulatory authorities limit our ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments. For the majority of the investments shown below, we own a share of the trust fund investments and do not hold individual securities. In 2006, we changed our method of assessing other-than-temporary declines in value and now consider all securities held by our nuclear decommissioning trusts with fair values below their cost basis to be other-than-temporarily impaired.

The fair value of these investments at December 31 is summarized below (dollars in thousands):

	2007				2006			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**	Amortized Cost	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity Securities	**$2,691**	**$1,467**	**$-**	**$4,158**	$2,439	$1,601	$-	$4,040
Debt Securities	**1,413**	**44**	**-**	**1,457**	1,382	14	-	1,396
Cash and other	**30**	**-**	**-**	**30**	40	-	-	40
Total	**$4,134**	**$1,511**	**$-**	**$5,645**	$3,861	$1,615	**$-**	$5,476

Information related to the fair value of debt securities at December 31, 2007 follows (dollars in thousands):

	Fair value of debt securities at contractual maturity dates				
	Less than 1 year	**1 to 5 years**	**5 to 10 years**	**After 10 years**	**Total**
Debt Securities	$16	$290	$283	$868	$1,457

NOTE 7 - RETAIL RATES AND REGULATORY ACCOUNTING

Retail Rates We recognize adequate and timely rate relief is required to maintain our financial strength, particularly since our rates do not include fuel or power cost adjustment mechanisms.

Our retail rates at December 31, 2007 are based on a December 7, 2006 PSB Order ("2006 Rate Order") approving a 4.07 percent rate increase effective January 1, 2007. The 2006 Rate Order provided, among other things, an allowed rate of return on common equity of 10.75 percent capped until our next rate proceeding. The return on common equity of our regulated business did not exceed the allowed return for 2007. Our retail rates at December 31, 2006 and 2005 were based on a March 29, 2005 PSB Order that provided for a 2.75 percent rate decrease and an allowed rate of return on common equity capped at 10.0 percent. That Order also resulted in a $21.8 million pre-tax charge to earnings in 2005.

At the time the 2006 Rate Order was issued, we had a pending Accounting Order request for recovery of $1.5 million of incremental replacement power costs subject to PSB approval. The 2006 Rate Order required us to record a regulatory asset or liability for any difference between the replacement power cost amortization included in the 4.07 percent rate increase and the amount approved by the PSB in the Accounting Order. On January 12, 2007, the PSB denied our Accounting Order request. This outcome had no 2006 income statement impact since the incremental replacement power costs were previously expensed in 2005, and it did not change the 4.07 percent rate increase effective January 1, 2007. Instead, we deferred the $1.5 million of revenue over two years and will continue such deferral until the next rate proceeding, at which time the total amount deferred will be returned to customers.

On May 15, 2007, we filed a request for a retail rate increase of $12.4 million, or 4.46 percent, in annual revenues based on the 2006 calendar year. On November 21, 2007, we reached a settlement in the case with the Vermont Department of Public Service ("DPS"), agreeing to a 2.30 percent rate increase (additional revenue of $6.4 million on an annual basis) effective for bills rendered on or after February 1, 2008. The agreement, which required PSB approval, also provided for a 10.71 percent rate of return on equity, capped until our next rate proceeding or approval of our Alternative Regulation Plan described below. As part of the settlement agreement, we also agreed to conduct an independent business process review to assure our cost controls are sufficiently challenging and that we are operating efficiently. The PSB approved the settlement agreement on January 31, 2008. The rate increase became effective February 1, 2008 and the business process review is expected to take place during 2008.

On August 31, 2007, we submitted an alternative regulation plan proposal for PSB approval. If approved, the plan would allow for quarterly rate adjustments to reflect power supply cost changes and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. The plan is designed to encourage efficiency in operations, and would replace the traditional ratemaking process. We cannot predict the outcome of this matter at this time.

On April 25, 2007, the PSB approved the rate design agreement that had been previously reached with the DPS. The rate design became effective for bills rendered on or after July 1, 2007, except for one rate class change with implementation delayed until September 1, 2007. The rate design results in a modest reallocation of revenue by customer class with greater emphasis on energy charges in reaction to wholesale market energy costs. The rate design agreement also included a comprehensive study of the need for new service offerings and further rate redesign. This is based on certain fundamental changes in how costs are incurred to serve load based on availability of advanced metering and communications and structural changes in the New England wholesale power market. The study is due to the PSB in April 2008.

Regulatory Accounting Under SFAS No. 71, we account for certain transactions in accordance with permitted regulatory treatment whereby regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. Regulatory assets and certain other deferred credits are being amortized in accordance with the 2006 Rate Order. These items, including other deferred credits, are also adjusted upward or downward in accordance with permitted regulatory treatment.

In the event that we no longer meet the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, we would be required to write off $17.3 million of regulatory assets (total regulatory assets of $32.0 million less pension and postretirement medical costs of $14.7 million), $9.0 million of other deferred charges - regulatory and $9.4 million of other deferred credits - regulatory. This would result in a total extraordinary charge to operations of $16.9 million pre-tax as of December 31, 2007. We would also be required to record pension and postretirement costs of $14.7 million on a pre-tax basis to Accumulated Other Comprehensive Loss as a reduction in stockholders' equity, and would be required to determine any potential impairment to the carrying costs of deregulated plant.

The table below provides a summary of Regulatory assets, Other deferred charges - regulatory and Other deferred credits - regulatory on the Consolidated Balance Sheets at December 31 (dollars in thousands):

	2007	2006
Regulatory assets		
Pension and postretirement medical costs - SFAS No. 158	**$14,673**	$31,705
Nuclear plant dismantling costs	**11,889**	15,033
Nuclear refueling outage costs - Millstone	**820**	308
Income taxes	**3,757**	3,810
Vermont Yankee sale costs (non-tax)	**-**	496
Vermont Yankee fuel rod maintenance deferral	**-**	231
Asset retirement obligations	**575**	501
Other	**274**	95
Regulatory assets	**$31,988**	$52,179
Other deferred charges - regulatory		
Vermont Yankee sale costs (tax)	**$673**	$3,130
Unrealized loss on power contract derivatives	**7,817**	7,997
Tree trimming and pole treating	**498**	710
Other	**-**	290
Other deferred charges - regulatory	**$8,988**	$12,127
Other deferred credits - regulatory		
Vermont utility overearnings 2001 - 2003	**$961**	$4,803
Connecticut Valley gain on termination of power contract	**-**	554
Asset retirement obligation - Millstone Unit #3	**3,085**	3,055
Vermont Yankee IRS settlement	**726**	1,088
Emission allowances and renewable energy credits	**616**	924
Unrealized gain on power contract derivatives	**707**	-
Environmental remediation	**1,834**	1,648
Vermont Yankee fire settlement	**870**	-
Other	**596**	615
Other deferred credits - regulatory	**$9,395**	$12,687

Pursuant to the 2006 Rate Order, the regulatory assets included in the table above are being recovered in retail rates, except for the asset retirement obligations. The recovery period for regulatory assets varies based on the nature of the costs. All regulatory assets are earning a return, except for income taxes, asset retirement obligations, nuclear plant dismantling costs, and pension and postretirement medical costs. Most items listed in other deferred credits - regulatory are being amortized for periods ranging from two to three years. Pursuant to PSB-approved Rate Orders, when a regulatory asset or liability is fully amortized, the corresponding rate revenue shall be booked as a reverse amortization in an opposing regulatory liability or asset account.

For additional information regarding pension and postretirement medical costs see Note 14 - Pension and Postretirement Medical Benefits. For additional information regarding income taxes see Note 15 - Income Taxes.

Environmental remediation represents the ratepayer portion of a 2006 reduction in environmental reserves that resulted from revised cost estimates for the Cleveland Avenue and Brattleboro sites described in Note 16 - Commitments and Contingencies. When we reduced the reserve, we reached an agreement with the DPS that approximately half of the reduction should be returned to ratepayers. Later in 2007, the PSB approved our Accounting Order request to record the ratepayer portion, including carrying costs, as a regulatory liability. Based on the January 31, 2008 PSB-approved Rate Order we will begin amortizing this liability over a two-year period beginning February 1, 2008.

The Vermont Yankee fire settlement is described in Note 16 - Commitments and Contingencies. Pursuant to the 2006 Rate Order, this deferred credit is being amortized over a three-year period beginning October 2007.

NOTE 8 - SHARE-BASED COMPENSATION

We have awarded share-based compensation to key employees and non-employee directors under several stock compensation plans. Awards under these plans have been comprised of: 1) stock options; 2) common stock that vests immediately or cliff vests based on service conditions; and 3) performance shares that vest based on performance, market and service conditions. At December 31, 2007 these plans included:

Plan	Shares Authorized	Stock options outstanding	Shares Available for future grant
1997 Stock Option Plan - Key Employees	350,000	132,458	-
2000 Stock Option Plan - Key Employees	350,000	190,680	-
2002 Long-Term Incentive Plan	350,000	122,869	73,843
Total	1,050,000	446,007	73,843

The 2002 Long-Term Incentive Plan ("2002 LTIP") authorizes the granting of stock options, stock appreciation rights, common shares and performance shares. Stock option grants were eliminated as a form of compensation to key employees and non-employee directors effective January 1, 2006. Stock appreciation rights have not been granted as a form of compensation.

Total share-based compensation expense recognized in the income statement for the last three years was $0.6 million in 2007, $0.9 million in 2006 and $0.1 million in 2005. The total income tax benefit recognized in the income statement for share-based compensation was $0.2 million in 2007, $0.3 million in 2006 and less than $0.1 million in 2005. No compensation costs were capitalized. Cash received from exercise of stock options was $1.1 million in 2007, $1.3 million in 2006 and $0.3 million in 2005. The tax benefit realized for the tax deductions from option exercises was $0.4 million in 2007 and $0.1 million in 2006 and 2005. These amounts are included in other paid in capital on the balance sheet.

Currently, stock options that are exercised and other stock awards are settled from authorized but un-issued common shares. Under the existing plans, they may also be settled by the issuance of treasury shares or through open market purchases of common shares. Awards other than stock options can also be settled in cash at the discretion of the Compensation Committee of our Board of Directors. Historically, these awards have been settled in the form of shares of our common stock.

Stock Options All outstanding stock options were granted at the fair market value of the common shares on the date of grant, and vested immediately. The maximum term of options is five years for non-employee directors and 10 years for key employees. Stock option activity during 2007 follows:

	Shares	Weighted Average Exercise Price
Options outstanding and exercisable at January 1	521,782	$16.92
Exercised	(75,775)	$15.12
Granted	-	-
Forfeited	-	-
Expired	-	-
Options outstanding and exercisable at December 31	446,007	$17.23

The total intrinsic value of stock options exercised during the last three years was $1.0 million in 2007, $0.3 million in 2006, and $0.1 million in 2005. The aggregate intrinsic value of options outstanding and exercisable as of December 31, 2007 was $6.1 million. The weighted average remaining contractual life for options outstanding and exercisable as of December 31, 2007 was 4.2 years.

The fair value of stock options granted in 2005 was estimated using the Black-Scholes option pricing model with the following assumptions:

	2005
Volatility	25.82%
Risk-free rate of return	4.35%
Dividend yield	5.11%
Expected life in years	5.04

The volatility assumption was based on the historical volatility of our common stock over a period equal to the option's expected term. The risk-free rate of return was based on the yield, at the grant date, of a U.S. Treasury security with a maturity period approximating the option's expected term. The dividend yield assumption was based on historical dividend payouts. The expected term of options granted was based on historical experience. Stock options granted during 2005 had a weighted-average grant date fair value of $3.55.

Common Stock and Nonvested Shares Under the 2002 LTIP, common stock can be granted to key employees and non-employee directors. The fair value of these awards is equal to the market value of the underlying common stock on the date of grant. The shares vest immediately or cliff vest over predefined service periods. Although full ownership of the shares does not transfer to the recipients until vested, the recipients have the right to vote the shares and to receive dividends from the date of grant. A summary of common and nonvested share activity during 2007 follows:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,000	$18.15
Granted	8,094	$32.22
Vested	(6,390)	$32.22
Deferred	(1,704)	$32.22
Forfeited	-	-
Nonvested at December 31	1,000	$18.15

In 2007, common stock was granted as part of the Board of Directors' annual retainer. These shares vest immediately, and individual directors can elect to defer receipt of their retainer under the terms of the Deferred Compensation Plan for Directors and Officers. The fair value of shares vested in 2007 totaled $0.2 million. Compensation expense was $0.3 million in 2007, $0.4 million in 2006 and $0.2 million in 2005. Unearned compensation expense at December 31, 2007 was of a nominal amount.

The weighted-average grant-date fair value of shares granted during 2006 was $21.42 per share and the fair value of shares vested totaled $0.4 million. The weighted-average grant-date fair value of shares granted during 2005 was $17.88 per share and the fair value of shares vested totaled $0.3 million.

Performance Shares The executive officer long-term incentive program is delivered in the form of contingently granted performance shares of common stock. At the start of each year a fixed number of performance shares are contingently granted for three-year service periods (referred to as performance cycles). The number of shares awarded at the end of each performance cycle is dependent on our performance compared to pre-established performance targets for relative Total Shareholder Return ("TSR") compared to all publicly traded electric and combined utilities, and on operational measures. The number of shares awarded at the end of the performance cycles ranges from zero to 1.5 times the number of shares targeted, based on actual performance versus targets. Dividends payable on performance shares during the performance cycle are reinvested into additional performance shares. Once the award is earned, shares become fully vested. If the participant's employment is terminated mid-cycle due to retirement, death, disability or a change-in-control, that employee or their estate is entitled to receive a pro rata portion of shares at target performance.

The fair value of performance shares for operational measures was estimated based on the market value of the shares on the grant date and the expected outcome of each measure. The grant-date fair value of performance shares with operational measures granted in 2007 was $22.75 per share. Compensation cost is recognized over the three-year performance cycle and is adjusted for the actual percentage of target achieved. The fair value of performance shares for TSR measures was estimated on the grant date using a Monte Carlo simulation model. The grant-date fair value of performance shares with TSR measures granted in 2007 was $20.86 per share. Compensation cost is recognized on a straight-line basis over the three-year performance cycle and is not adjusted for the actual percentage of target achieved. The weighted-average assumptions used in the Monte Carlo valuation for TSR performance shares granted in 2007 and 2006 are shown in the table below.

	2007	2006
Volatility	**25.97%**	23.10%
Risk-free rate of return	**4.68%**	4.29%
Dividend yield	**4.04%**	4.98%
Term (years)	**3.0**	3.0

The volatility assumption was based on the historical volatility of our common stock over the three-year period ending on the grant date. The risk-free rate of return was based on the yield, at the grant date, of a U.S. Treasury security with a maturity period of three years. The dividend yield assumption was based on historical dividend payouts. The expected term of performance shares is based on a three-year cycle.

A summary of performance share activity, excluding estimated dividend equivalents, during 2007 follows:

	Shares	**Weighted Average Grant-Date Fair Value**
Outstanding at January 1 (a)	56,600	$18.75
Granted (b)	28,600	$21.81
Vested (c)	(17,893)	$20.19
Forfeited	(4,907)	$22.17
Outstanding at December 31 (d)	62,400	$19.47

(a) Previously reported 64,028 performance shares outstanding at December 31, 2006 which included estimated dividend equivalents that are no longer shown in the table.
(b) Performance shares contingently granted for the 2007 - 2009 performance cycle.
(c) Estimated shares earned for the 2005 - 2007 performance cycle.
(d) The number of common shares related to performance shares may range from zero to 150 percent of the number shown in the table above based on the achievement of operational and TSR measures relative to the three-year performance cycles.

Compensation expense related to performance share plans amounted to $0.3 million in 2007, $0.5 million in 2006 and a $0.1 million credit in 2005. Unrecognized compensation expense for outstanding performance shares as of December 31, 2007 amounts to approximately $0.5 million and is expected to be recognized over 1.5 years.

The weighted-average grant-date fair value of shares granted during 2006 was $17.50 per share and the fair value of shares vested was zero because targeted financial goals were not achieved for the 2004 - 2006 performance cycle. The weighted-average grant-date fair value of performance shares granted during 2005 was $20.62 per share, and the fair value of shares vested was $0.8 million.

NOTE 9 - TREASURY STOCK

Treasury stock is recorded at cost, $22.75 per share, and results in a reduction of shareholders' equity on the Consolidated Balance Sheet. In April 2006, we purchased 2,249,975 shares of our common stock at $22.50 per share using proceeds from the December 20, 2005 sale of Catamount. In July 2007, we began using Treasury shares to meet reinvestment needs under the Dividend Reinvestment Plan.

NOTE 10 - PREFERRED AND PREFERENCE STOCK NOT SUBJECT TO MANDATORY REDEMPTION

Preferred and preference stock not subject to mandatory redemption at December 31 consisted of the following (dollars in thousands):

	2007	2006
Preferred stock, $100 par value, outstanding:		
4.150% Series; 37,856 shares	**$3,786**	$3,786
4.650% Series; 10,000 shares	**1,000**	1,000
4.750% Series; 17,682 shares	**1,768**	1,768
5.375% Series; 15,000 shares	**1,500**	1,500
Total preferred and preference stock not subject to mandatory redemption	**$8,054**	$8,054

There are 500,000 shares authorized of the Preferred Stock, $100 Par Value class that can be issued with or without mandatory redemption requirements. At December 31, 2007, a total of 110,538 shares were outstanding, including 80,538 that are not subject to mandatory redemption and are listed in the table above, and 30,000 that are subject to mandatory redemption and described in Note 11 - Preferred Stock Subject to Mandatory Redemption. None of the outstanding Preferred Stock, $100 Par Value, is convertible into shares of any other class or series of our capital stock or any other security.

There are 1,000,000 shares authorized of Preferred Stock, $25 Par Value, and 1,000,000 shares authorized of Preference Stock, $1 Par Value. None of the shares are subject to mandatory redemption. There were none outstanding, issued or redeemed in 2007, 2006 or 2005.

All series of the Preferred Stock, $100 Par Value class are of equal ranking, including those subject to mandatory redemption. Each series is entitled to a liquidation preference over the holders of common stock that is equal to Par Value, plus accrued and unpaid dividends, and a premium if liquidation is voluntary. In general, there are no "deemed" liquidation events. Holders of the Preferred Stock have no voting rights, except as required by Vermont law, and except that if accrued dividends on any shares of Preferred Stock have not been paid for more than two full quarters, each share will have the same voting power as Common Stock. If accrued dividends have not been paid for four or more full quarters, the holders of the Preferred Stock have the right to elect a majority of our Board of Directors. There are no dividends in arrears for preferred stock not subject to mandatory redemption.

All series of Preferred Stock are currently subject to redemption and retirement at our option upon vote of at least three-quarters of our Board of Directors in accordance with the specific terms for each series and upon payment of the Par Value, accrued dividends and a premium to which each would be entitled in the event of voluntary liquidation, dissolution or winding up of our affairs. At December 31, 2007, premiums payable on each series of non-redeemable preferred stock if such an event were to occur are as follows:

Preferred and Preference Stock	**Premiums Per Share**
4.150% Series	$5.500
4.650% Series	$5.000
4.750% Series	$1.000
5.375% Series	$5.000

NOTE 11 - PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION

We have one series of Preferred Stock, $100 Par Value that is subject to mandatory redemption, 8.3 Percent Series Preferred Stock, with shares outstanding of 30,000 at December 31, 2007, 40,000 at December 31, 2006 and 60,000 at December 31, 2005. All of the provisions described in Note 10 - Preferred and Preference Stock Not Subject to Mandatory Redemption are the same for the 8.3 Percent Series Preferred Stock, except that at December 31, 2007 premiums payable in the event of voluntary liquidation, dissolution or winding up of our affairs are at $2.075 per share. There are no dividends in arrears for the 8.3 Percent Series Preferred Stock.

The mandatory redemption requirement for the 8.3 Percent Series Preferred Stock is $1.0 million (10,000 shares at par value) per annum. We may, at our option, also redeem at par an additional non-cumulative $1.0 million annually. We are scheduled to make annual payments of $1.0 million in 2008, 2009 and 2010 under the mandatory redemption requirements. Thereafter the 8.3 Percent Series Preferred Stock will be fully redeemed. In the fourth quarter of 2007 and 2006, we paid our transfer agent $1.0 million for the mandatory redemption payment that is effective January 1. The payments to the transfer agent are included in Special Deposits on the Consolidated Balance Sheets.

Dividends paid on preferred stock subject to mandatory redemption are included in Other interest on the Consolidated Statements of Income, and amounted to $0.2 million in 2007, $0.3 million in 2006 and $0.5 million in 2005.

NOTE 12 - LONG-TERM DEBT

Long-term debt at December 31 consisted of the following (dollars in thousands):

	2007	2006
First Mortgage Bonds		
6.27%, Series NN, due 2008	**$3,000**	$3,000
5.00%, Series SS, due 2011	**20,000**	20,000
5.72%, Series TT, due 2019	**55,000**	55,000
6.90%, Series OO, due 2023	**17,500**	17,500
8.91%, Series JJ, due 2031	**15,000**	15,000
New Hampshire Industrial Development Authority Bonds		
Variable 3.75%, due 2009	**5,450**	5,450
Total long-term debt	**115,950**	115,950
Less current amount payable, due within one year	**(3,000)**	-
Total long-term debt less current portion	**$112,950**	$115,950

Substantially all of our utility property and plant is subject to liens under our First Mortgage Bonds. The First Mortgage Bonds are callable at our option at any time upon payment of a make-whole premium, calculated as the excess of the present value of the remaining scheduled payments to bondholders, discounted at a rate that is 0.5 percent higher than the comparable U.S. Treasury Bond yield, over the early redemption amount.

The New Hampshire Industrial Development Authority Bonds are pollution control revenue bonds that carry an interest reset provision. These bonds are callable at our option or the bondholders' option on the rate reset date. The final rate reset occurred December 1, 2004. As of December 31, 2007, the bonds are only callable at our option in special circumstances involving unenforceability of the indenture or a change in the usability of the project.

Our debt financing documents do not contain cross-default provisions to affiliates outside of the consolidated entity. Certain of our debt financing documents contain cross-default provisions to our wholly owned subsidiaries, East Barnet, C.V. Realty, Inc. and Custom Investment Corporation. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions or the levy of significant judgments or attachments against our property. Currently, we are not in default under any of our debt financing documents. Scheduled sinking fund payments and maturities for the next five years are $3.0 million in 2008, $5.5 million in 2009, $0 in 2010, $20.0 million in 2011 and $0 in 2012.

Letters of credit: We have three outstanding secured letters of credit, issued by one bank, totaling $16.9 million in support of three separate issues of industrial development revenue bonds totaling $16.3 million, of which $5.5 million is included in Long-Term Debt and $10.8 million is included in Notes Payable. We pay an annual fee of 0.9 percent on the letters of credit, based on our secured long-term debt rating. These letters of credit expire on November 30, 2008. Pursuant to a bank commitment dated March 10, 2008, we have the sole option to extend the maturity of these letters of credit to November 30, 2009. The letters of credit contain cross-default provisions to East Barnet, a wholly owned subsidiary. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments, insolvency or violations under ERISA benefit plans. At December 31, 2007, there were no amounts drawn under these letters of credit.

Covenants: Our long-term debt indentures, letters of credit, and credit facility contain financial and non-financial covenants. The most restrictive financial covenants include maximum debt to total capitalization of 65 percent, and minimum interest coverage of 2.0 times. At December 31, 2007, we were in compliance with all covenants.

Dividend and Optional Stock Redemption Restrictions: Our $25.0 million revolving credit facility described in Note 13 - Notes Payable and Credit Facility restricts optional redemptions of capital stock. The First Mortgage Bond indenture and our Articles of Association also contain certain restrictions on the payment of cash dividends on and optional redemptions of all capital stock. Under the most restrictive of these provisions, about $62.9 million of retained earnings was not subject to such restriction at December 31, 2007. The Articles also restrict the payment of common dividends or purchase of any common shares if the common equity level falls below 25 percent of total capital, applicable only as long as Preferred Stock is outstanding. Our Articles of Association also contain a covenant that requires us to maintain a minimum common equity level of about $3.3 million as long as any Preferred Stock is outstanding.

NOTE 13 - NOTES PAYABLE AND CREDIT FACILITY

Notes payable at December 31 consisted of the following (dollars in thousands):

	2007	2006
Revenue Bonds		
Vermont Industrial Development Authority Bonds		
Variable, due 2013 (3.05% at December 31, 2007)	**$5,800**	$5,800
Connecticut Development Authority Bonds		
Variable, due 2015 (3.55% at December 31, 2007)	**5,000**	5,000
Short term note payable		
Variable, due June 30, 2008 (5.44% at December 31, 2007)	**53,000**	-
Total Notes Payable	**$63,800**	$10,800

Notes Payable: The revenue bonds are floating rate, monthly demand pollution-control bonds. There are no interim sinking fund payments due prior to their maturity. The interest rates reset monthly. Both series are callable at par as follows: 1) at our option or bondholders' option on each monthly interest payment date; or 2) at the option of the bondholders on any business day. There is a remarketing feature if the bonds are put for redemption. Historically, these bonds have been remarketed in the secondary bond market. We have outstanding secured short-term letters of credit that support these bonds, as described in Note 12 - Long-Term Debt.

Short-term Note: At December 31, 2007 we had a six-month unsecured term note in the principal amount of $53.0 million with a major lending institution. The loan is payable June 30, 2008 and currently carries an adjustable borrowing rate tied to overnight LIBOR plus a fixed spread that decreases as our credit rating improves. Other variable interest rate options are available to us, such as prime or federal funds rate plus a fixed spread. Fixed rate options are also available based on LIBOR for a time period of one, two or three months plus a fixed spread that decreases as our credit rating improves. There are no caps on these interest rate options. Pursuant to a commitment from the lending institution dated February 11, 2008, we have the sole option to extend the maturity of the term note to March 31, 2009. Our obligation under the term note is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The term note contains cross-default provisions to any of our subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or involuntary liquidation, reorganization or bankruptcy.

Credit Facility: We have a 364-day, $25.0 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated December 28, 2007. This replaces the previous credit facility, which was to expire in October 2008. It contains financial and non-financial covenants as discussed in Note 12 - Long-Term Debt. Pursuant to a commitment from the credit facility bank dated February 11, 2008, we also have the sole option to extend the maturity of the credit facility to March 31, 2009. Our obligation under the Credit Agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. Financing terms and costs include an annual commitment fee of 0.225 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.9 percent on the average daily amount of letters of credit outstanding, all based on our unsecured long-term debt rating. Terms also include the requirement to collateralize any outstanding letters of credit in the event of a default under the credit facility. The facility contains a Material Adverse Effect ("MAE") clause (a standard that requires greater adversity than a Material Adverse Change clause). This clause is in effect only when our credit rating is below investment grade; therefore, it is currently in effect. The MAE clause could allow the lending institution to deny a transaction under the credit facility at the point of request. The credit facility also contains cross-default provisions to any of our subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or voluntary or involuntary liquidation, reorganization or bankruptcy. At December 31, 2007 no amounts were outstanding under this new facility, but we did issue two letters of credit totaling $6.0 million to support certain power-related performance assurance requirements. No amounts have been drawn under the letters of credit, which expire in December 2008. Under the old credit facility, a $5.0 million letter of credit, formerly in support of performance assurance requirements with a power counterparty, was outstanding until early January 2008.

NOTE 14 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

We have a qualified, non-contributory, defined-benefit, trusteed pension plan ("Pension Plan") covering all union and non-union employees. 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. They are eligible to receive monthly benefits or a lump sum amount. Our funding policy is to contribute an amount equal to the annual actuarial cost or at least a statutory minimum to a trust. We are not required by our union contract to contribute to multi-employer plans. At the end of 2005, we adopted the RP-2000 mortality table that replaced the GAM 94 table.

We also sponsor a defined-benefit postretirement medical plan that covers all employees who retire with 10 or more years of service after age 45 and who are at least age 55. We fund this obligation through a Voluntary Employees' Benefit Association and 401(h) Subaccount in the Pension Plan. Retirees under the age of 65 ("pre-65") participate in plan options similar to active employees. Retirees at or over the age of 65 ("post-65") receive limited coverage with a $10,000 annual individual maximum. Company contributions to retiree medical are capped for employees retiring after 1995 at $0.3 million per year for pre-65 retirees and are capped at a nominal amount for post-65 retirees. There are no retiree contributions for pre-1996 retirees.

SFAS No. 158 requires an employer with a defined benefit plan or other postretirement plan to recognize an asset or liability on its balance sheet for the overfunded or underfunded status of the plan. For pension plans, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For postretirement benefit plans, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. Our pension and postretirement benefit obligations and plan assets are valued annually as of a September 30 measurement date.

Benefit Obligation The changes in benefit obligation for pension and postretirement medical benefits at December 31 follow (dollars in thousands):

	Pension Benefits		**Postretirement Medical Benefits**	
	2007	2006	**2007**	2006
Benefit obligation at beginning of measurement date	**$103,853**	$104,250	**$26,276**	$30,300
Service cost	**3,552**	3,686	**577**	706
Interest cost	**6,242**	5,971	**1,507**	1,696
Actuarial loss (gain)	**(11,048)**	(2,546)	**(33)**	(4,678)
Plan participants' contributions	**-**	-	**987**	727
Gross benefits paid	**(6,549)**	(7,508)	**(2,993)**	(2,629)
less: federal subsidy on benefits paid	**-**	-	**199**	154
Projected obligation as of measurement date (September 30)	**$96,050**	$103,853	**$26,520**	$26,276
Accumulated obligation as of measurement date (September 30)	**$78,894**	$83,549	**-**	-

The reduction in our accumulated postretirement benefit obligation due to the impact of the Medicare Part D subsidy is $3.0 million for 2007 and $3.6 million for 2006.

The present value of future contributions from Postretirement Plan participants was $35.1 million for 2007 and $34.6 million for 2006.

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at the September 30 measurement date are shown in the table that follows. The selection methodology used in determining discount rates includes portfolios of "Aa" bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million in par value. As of September 30, 2007, the following weighted-average assumptions for pension and postretirement medical benefits were used in determining our related liabilities at December 31:

	Pension Benefits		**Postretirement Medical Benefits**	
	2007	2006	**2007**	2006
Discount rates	**6.30%**	5.95%	**6.15%**	5.80%
Rate of increase in future compensation levels	**4.25%**	4.25%	**4.25%**	4.25%

For measurement purposes, a 9.5 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2007, for pre-65 and post-65 claims costs. The rate is assumed to decrease 0.5 percent each year until 2010, and to decrease 1 percent in each of the subsequent years until an ultimate trend rate of 5.0 percent is reached in 2013.

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect (dollars in thousands):

	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on postretirement medical benefit obligation as of September 30, 2007	$2,051	$(1,733)
Effect on aggregate service and interest costs	$205	$(166)

Asset Allocation The asset allocations at the measurement date for 2007 and 2006, and the target allocation for 2008, by asset category, are as follows:

	Pension Plan			Postretirement Medical Plan		
	2008 Target	**2007**	2006	**2008 Target**	**2007**	2006
Equity securities	**67.0%**	68.1%	65.9%	**67.0%**	67.2%	0.0%
Debt securities	**33.0%**	31.9%	34.1%	**33.0%**	32.8%	0.0%
Other	**-**	-	-	**-**	-	100.0%
Total	**100.0%**	100.0%	100.0%	**100.0%**	100.0%	100.0%

Investment Strategy Our pension investment policy seeks to achieve sufficient growth to enable the Pension Plan to meet our future benefit obligations to participants, to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 67 percent of plan assets be invested in equity securities and 33 percent of plan assets be invested in debt securities. The debt securities are fixed income assets that are invested in longer-duration bonds to match changes in plan liabilities.

Our postretirement medical benefit plan investment policy seeks to achieve sufficient funding levels to meet future benefit obligations to participants and minimize near-term cost volatility. In early 2007, the plan assets were invested in cash equivalents. Beginning in May 2007, we adopted an asset allocation mix similar to that of the Pension Plan assets.

Change in Plan Assets The changes in Plan assets as of the measurement date are shown below (dollars in thousands):

	Pension Plan		Postretirement Medical Plan	
	2007	2006	**2007**	2006
Fair value of plan assets at beginning of measurement date	**$86,131**	$67,784	**$11,526**	$6,174
Actual return on plan assets	**10,718**	5,091	**605**	369
Employer contributions	**4,056**	20,764	**3,139**	6,885
Plan participants' contributions	**-**	-	**987**	727
Gross benefits paid	**(6,549)**	(7,508)	**(2,993)**	(2,629)
Fair value of assets as of measurement date (September 30)	**$94,356**	$86,131	**$13,264**	$11,526

Funded Status The Plans' funded status was as follows (dollars in thousands):

	Pension Plan		Postretirement Medical Plan	
	2007	2006	**2007**	2006
Fair value of assets	**$94,356**	**$86,131**	**$13,264**	$11,526
Benefit obligation	**(96,050)**	**(103,853)**	**(26,520)**	(26,276)
CVPS contributions between measurement and year-end dates	**-**	**-**	**153**	593
Funded Status	**$(1,694)**	**$(17,722)**	**$(13,103)**	$(14,157)

The increase in the Pension Plan funded status of $16.0 million for 2007 versus 2006 resulted from an increase of $8.2 million in the fair value of assets as shown in the table above, and a decrease of $7.8 million in the benefit obligation, primarily due to actuarial gains as shown in the table above. The actuarial gains were primarily the result of higher-than-expected returns on plan assets, changes in plan demographics, and changes in actuarial assumptions.

Amounts recognized in the Consolidated Balance Sheets Amounts related to accrued benefit costs recognized in our Consolidated Balance Sheets at December 31 consisted of (dollars in thousands):

	Pension Benefits		Postretirement Medical Benefits	
	2007	2006	**2007**	2006
Non-current liability	**$(1,694)**	$(17,722)	**$(13,103)**	$(14,157)

In 2007, the Postretirement Medical Plan non-current liability shown above included an actuarial estimate of $0.2 million related to our Medicare D subsidy payments expected in the first quarter of 2008.

Amounts recognized in Regulatory Assets and Accumulated Other Comprehensive Loss ("AOCL") The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2007 consisted of (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	**AOCL**	**Total**	**Regulatory Asset**	**AOCL**	**Total**
Net actuarial loss	**$(888)**	**$(3)**	**$(891)**	**$11,622**	**$35**	**$11,657**
Prior service cost	**2,577**	**8**	**2,585**	**1**	**-**	**1**
Transition obligation	**-**	**-**	**-**	**1,275**	**4**	**1,279**
Net amount recognized	**$1,689**	**$5**	**$1,694**	**$12,898**	**$39**	**$12,937**

The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2006 consisted of (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	**AOCL**	**Total**	**Regulatory Asset**	**AOCL**	**Total**
Net actuarial loss	$14,710	$28	$14,738	$12,391	$24	$12,415
Prior service cost	2,978	6	2,984	1	-	1
Transition obligation	-	-	-	1,532	3	1,535
Net amount recognized	$17,688	$34	$17,722	$13,924	$27	$13,951

Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets and Other Comprehensive Income Components of pre-tax changes were as follows (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	**AOCL**	**Total**	**Regulatory Asset**	**AOCL**	**Total**
Current year actuarial (gain)/loss	$(15,017)	$(30)	$(15,047)	$280	$13	$293
Amortization of actuarial loss	(581)	(1)	(582)	(1,049)	(2)	(1,051)
Amortization of prior service cost	(401)	2	(399)	-	-	-
Amortization of transition obligation	-	-	-	(257)	1	(256)
Net amount recognized	$(15,999)	$(29)	$(16,028)	$(1,026)	$12	$(1,014)

Net Periodic Benefit Costs Components of net periodic benefit costs were as follows (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	2007	2006	2005	**2007**	2006	2005
Service cost	**$3,552**	$3,686	$3,227	**$578**	$706	$512
Interest cost	**6,242**	5,971	5,856	**1,507**	1,695	1,444
Expected return on plan assets	**(6,719)**	(5,744)	(5,267)	**(932)**	(716)	(477)
Amortization of actuarial loss	**582**	785	196	**1,051**	1,591	1,113
Amortization of prior service cost	**399**	401	401	**-**	1	1
Amortization of transition (asset) obligation	**-**	-	-	**256**	256	256
Net periodic benefit cost	**4,056**	5,099	4,413	**2,460**	3,533	2,849
Less amount allocated to other accounts	**693**	885	702	**420**	613	453
Net benefit costs expensed	**$3,363**	$4,214	$3,711	**$2,040**	$2,920	$2,396

Benefit Cost Assumptions Weighted-average assumptions use to determine net periodic costs at measurement date (September 30) are shown in the table below. The weighted-average assumptions shown for 2007, which were set at September 30, 2006, were used in determining 2007 expense. Likewise, the 2006 and 2005 weighted-average assumptions were used in determining 2006 and 2005 expense, respectively.

	Pension Benefits			**Postretirement Medical Benefits**		
	2007	2006	2005	**2007**	2006	2005
Weighted-average discount rates	**5.95%**	5.65%	6.00%	**5.80%**	5.65%	6.00%
Expected long-term return on assets	**8.25%**	8.25%	8.25%	**8.25%**	8.25%	8.25%
Rate of increase in future compensation levels	**4.25%**	4.00%	3.75%	**4.25%**	4.00%	3.75%

2008 Cost Amortizations: The estimated amounts that will be amortized from regulatory assets and accumulated other comprehensive income into net periodic benefit cost in 2008 are as follows (dollars in thousands):

	Pension Benefits	**Postretirement Medical Benefits**
Actuarial loss	$ -	$1,052
Prior service cost	397	1
Transition benefit obligation	-	256
Total	$397	$1,309

Expected Long-Term Rate of Return on Plan Assets We expect an average annual long-term return on the pension asset portfolio of 8.25 percent, based on a representative allocation within the target asset allocation described above. In formulating this assumed rate of return, we considered historical returns by asset category and expectations for future returns by asset category based, in part, on simulated capital market performance over the next 10 years.

The Pension Plan assets earned a rate of return of 12.8 percent, 8.2 percent and 15.6 percent, respectively, for the Plan years ended September 30, 2007, 2006 and 2005

Based on the postretirement medical benefit plan investment policy described above, we expect an average annual long-term return for the postretirement portfolio of 8.25 percent. In formulating this assumed long-term rate of return, we considered asset categories and expectations for future returns by asset category.

Pension and postretirement medical benefit expenses for 2007 were based on an expected long-term rate of return on assets of 8.25 percent. The same percentage will be used to determine the 2008 expenses.

Trust Fund Contributions The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. Pension Plan trust fund contributions were $4.1 million in June 2007. Postretirement Medical Plan trust fund contributions were $2.4 million in June 2007 and $0.2 million in December 2007.

Expected Cash Flows The table below reflects the total benefits expected to be paid from the external Pension Plan trust fund or from our assets, including both our share of the pension and postretirement benefit costs and the share of the postretirement medical benefit cost funded by participant contributions. Expected contributions reflect amounts expected to be contributed to funded plans. Of the benefits expected to be paid in 2008, approximately $5.1 million will be paid from the Pension Plan trust fund, and $2.2 million will be paid from the postretirement medical trust funds to reimburse us for out-of-pocket benefit payments. Information about the expected cash flows for the Pension Plan and postretirement medical benefit plans is as follows (dollars in thousands):

	Pension Benefits	**Postretirement Medical Benefits**	
		Gross	**Expected Federal Subsidy**
Employer Contributions			
2008	$2,500	$2,400	
Expected Benefit Payments			
2008	$5,129	$2,165	$220
2009	7,988	2,239	241
2010	7,309	2,305	269
2011	7,695	2,342	294
2012	10,307	2,370	323
2013 - 2017	45,525	12,199	1,981

As of October 1, 2007, the Medicare Part D subsidy reduced the postretirement benefit obligation by $3.0 million and reduced the 2007 net periodic benefit cost by $0.6 million. The estimated Medicare Part D subsidy included in the expected gross postretirement medical benefit payments is shown above.

Other

Long-term Disability We record nonaccumulating post-employment long-term disability benefits in accordance with SFAS No. 5. The year-end post-employment medical benefit obligations of $1.4 million in 2007 and $1.8 million in 2006 are reflected in our Consolidated Balance Sheets as Accrued pension and medical benefit obligations, and $0.2 million was recorded as Other current liabilities in 2007 and in 2006. The pre-tax post-employment benefit costs charged to expense, including insurance premiums, were $0.2 million in 2007, $0.6 million in 2006 and $0.2 million in 2005.

401(k) Savings Plan We maintain a 401(k) Savings Plan for substantially all employees. This savings plan provides for employee pre-tax and post-tax contributions up to specified limits. We match employee pre-tax contributions after one year of service. On January 1, 2007, the match increased from up to 4.0 percent to up to 4.25 percent of eligible compensation. Eligible employees are at all times vested 100 percent in their pre-tax and post-tax contribution account and in their matching employer contribution. Our matching contributions amounted to $1.3 million in 2007, and $1.2 million in 2006 and 2005.

Other Benefits We also provide an Officers' Supplemental Retirement Plan ("SERP") to certain of our executive officers. The SERP is designed to supplement the retirement benefits available through our qualified Pension Plan.

The accumulated year-end SERP benefit obligation, based on the same discount rate described above for pension, was $3.5 million in 2007 and $3.6 million in 2006 and is reflected in the Consolidated Balance Sheets as Accrued pension and benefit obligations, and $0.3 million was recorded as Other current liabilities in 2007. The accumulated SERP benefit obligation included a comprehensive gain of $0.2 million in 2007 and $0.3 million in 2006. The pre-tax SERP benefit costs charged to expense totaled $0.4 million in 2007, $0.6 million in 2006 and $0.5 million for 2005. At December 31, 2006, a pre-tax adjustment of $0.8 million was recorded to accumulated other comprehensive income related to adoption of SFAS No. 158. This adjustment included $0.7 million of net losses and $0.1 million of prior service costs.

Benefits are funded through life insurance policies held by a Rabbi Trust. Rabbi Trust assets are not considered plan assets for accounting purposes under SFAS No. 87. The year-end balance included in Investments and Other Assets on our Consolidated Balance Sheets was $7.5 million in 2007 and $7.1 million in 2006. Changes in cash surrender value are included in Other income on our Consolidated Statements of Income. These pre-tax amounts were a decrease of $0.2 million for 2007, an increase of $0.2 million for 2006 and a nominal decrease for 2005.

NOTE 15 - INCOME TAXES

The income tax expense (benefit) from continuing operations as of December 31 consisted of the following (dollars in thousands):

	2007	2006	2005
Federal:			
Current	**$2,899**	$4,875	$(679)
Deferred	**2,566**	3,144	(1,187)
Investment tax credits, net	**(379)**	(379)	(379)
	5,086	7,640	(2,245)
State:			
Current	**1,124**	1,311	432
Deferred	**539**	1,055	(269)
	1,663	2,366	163
Total federal and state income taxes	**$6,749**	$10,006	$(2,082)
Federal and state income taxes charged to:			
Operating expenses	**$5,291**	$8,569	$(2,264)
Other income	**1,458**	1,437	182
	$6,749	$10,006	$(2,082)

The reconciliation between income taxes computed by applying the U.S. federal statutory rate and the reported income tax expense (benefit) from continuing operations as of December 31 follows (dollars in thousands):

	2007	2006	2005
Income (loss) before income tax	**$22,553**	$28,107	$(672)
Federal statutory rate	**35%**	35%	35%
Federal statutory tax expense	**7,894**	9,838	(235)
Increase (benefit) in taxes resulting from:			
Dividend received deduction	**(647)**	(494)	(520)
State income taxes net of federal tax benefit	**1,106**	1,729	69
Investment credit amortization	**(379)**	(379)	(379)
Renewable Electricity Production Credit	**(275)**	(273)	(196)
AFUDC equity	**198**	194	194
Life insurance	**(139)**	(236)	(191)
Medicare Part D	**(193)**	(107)	(96)
Domestic production activities deduction	**(147)**	(63)	-
Change in estimate for tax contingencies	**-**	(191)	(741)
Other	**(669)**	(12)	13
Total income tax expense (benefit)	**$6,749**	$10,006	$(2,082)
Effective combined federal and state income tax rate	**29.9%**	35.6%	309.8%

As a result of the January 1, 2007 adoption of FIN 48, we decreased previously recorded tax contingencies by $0.6 million. In accordance with FIN 48 adoption guidelines this decrease did not affect the effective tax rate. We decreased estimated tax contingencies by $0.2 million in 2006 and $0.7 million in 2005 due to a reduction in potential tax liabilities.

We increased our estimate of FIN 48 unrecognized tax benefit by $1.9 million in 2007. In accordance with FIN 48 adoption guidelines and the impact of deferred tax accounting, a net decrease in unrecognized tax benefits of less than $0.1 million affected the effective tax rate.

SFAS No. 109 prohibits the recognition of all or a portion of deferred income tax benefits if it is more likely than not that the deferred tax asset will not be realized. There were no valuation allowances recorded for the periods ended 2007 and 2006.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31 are presented below (dollars in thousands):

	2007	2006
Deferred tax assets - current		
Reserves for uncollectible accounts	**$710**	$692
Deferred compensation and pension	**968**	698
Environmental costs accrual	**188**	131
SFAS No. 5 loss accrual	**485**	485
401(k) contribution carryforward	**-**	71
Active Medical Accrual	**337**	346
SFAS No. 133 - derivative instruments	**1,307**	630
Other accruals	**223**	475
Total deferred tax assets - current	**4,218**	3,528
Deferred tax liabilities - current		
Property tax accruals	**265**	319
Prepaid insurance	**315**	310
Total deferred tax liabilities - current	**580**	629
Net deferred tax assets - current	**3,638**	2,899

Deferred tax assets - long term		
Equity investments	**1,348**	1,348
Accruals and other reserves not currently deductible	**612**	1,438
Deferred compensation and pension	**508**	-
Environmental costs accrual	**1,333**	1,378
Millstone decommissioning costs	**2,288**	2,232
Contributions in aid of construction	**2,198**	2,119
Revenue deferral - Vermont utility earnings	**389**	1,947
SFAS No. 5 - loss accrual	**3,393**	3,877
SFAS No. 133 - derivative instruments	**1,861**	2,611
SFAS No. 158 - benefit liability	**6,204**	13,220
SFAS No. 112 - retiree medical benefits	**637**	467
Connecticut Valley gain deferral	**-**	225
Total deferred tax assets - long term	**20,771**	30,862
Deferred tax liabilities		
Property, plant and equipment	**40,190**	38,765
Net SFAS No. 109 regulatory asset	**1,523**	1,544
Vermont Yankee sale	**672**	3,331
SFAS No. 158 - regulatory asset	**5,946**	13,220
SFAS No. 133 - derivative instruments	**3,168**	3,241
Decommissioning costs	**1,909**	1,906
Other	**1,029**	1,322
Total deferred tax liabilities - long term	**54,437**	63,329
Net deferred tax liabilities - long term	**33,666**	32,467
Net deferred tax liabilities	**$30,028**	$29,568

A summary of the liabilities and assets combining current and long-term:

Total deferred tax liabilities - current and long-term	**$55,017**	$63,958
Less total deferred tax assets - current and long-term	**24,989**	34,390
Net deferred tax liabilities	**$30,028**	$29,568

NOTE 16 - COMMITMENTS AND CONTINGENCIES

Nuclear Decommissioning Obligations We are obligated to pay our share of nuclear decommissioning costs for nuclear plants in which we have an ownership interest. We have a 1.7303 joint-ownership percentage in Millstone Unit # 3, in which Dominion Nuclear Connecticut ("DNC") is the lead owner with about 93.4707 percent of the plant joint-ownership. We have an external trust dedicated to funding our joint-ownership share of future decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. We have also suspended contributions to the Trust Fund, but could choose to renew funding at our own discretion as long as the minimum requirement is met or exceeded. If a need for additional decommissioning funding is necessary, we will be obligated to resume contributions to the Trust Fund.

We have equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down. Our obligations related to these plants are described in Note 3 - Investments in Affiliates.

We also had a 35 percent ownership interest in the Vermont Yankee nuclear power plant through our equity investment in VYNPC, but the plant was sold in 2002. Our obligation for plant decommissioning costs ended when the plant was sold, except that VYNPC retained responsibility for the pre-1983 spent fuel disposal cost liability. VYNPC has a dedicated Trust Fund that meets most of the liability.

The Price-Anderson Act ("Act") currently limits public liability from a single incident at a nuclear power plant to about $10 billion. The Energy Policy Act of 2005, enacted in August 2005, extends the Act, which expired in 2003, for 20 years and provides a framework for immediate, no-fault insurance coverage for the public in the event of a nuclear reactor accident. The Act consists of two levels of coverage. The primary level provides liability insurance coverage of $300 million. If this amount is not sufficient to cover claims arising from an accident, the second level, referred to as secondary financial protection, applies. For the second level, each nuclear plant must pay a premium in arrears equal to its proportionate share of the excess loss, up to a maximum of $100.6 million per reactor per incident, limited to a maximum annual assessment of $15 million. These assessments will be adjusted for inflation. Currently, based on our joint-ownership interest in Millstone Unit #3, we could become liable for about $0.3 million of such maximum assessment per incident per year. Maine Yankee, Connecticut Yankee and Yankee Atomic maintain $100 million in Nuclear Liability Insurance, but have received exemptions from participating in the secondary financial protection program under the Act.

Long-Term Power Purchases *Vermont Yankee:* We are purchasing our entitlement share of Vermont Yankee plant output through the PPA between ENVY and VYNPC. One remaining secondary purchaser continues to receive a small percentage (less than 0.2 percent) of our entitlement. An uprate in 2006 increased the plant's operating capacity by approximately 20 percent. After completion of the uprate, VYNPC's entitlement to plant output declined from 100 percent to 83 percent, and our entitlement share declined from 35 percent to 29 percent. ENVY has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor.

Prices under the PPA increase $1 per megawatt-hour each calendar year, from $41 in 2008 to $45 in 2012. The PPA contains a provision known as the "low market adjuster", which calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price. Estimated annual purchases are expected to range from $59.3 million to $65.1 million for 2008 through 2011, and $17.5 million for 2012 when the contract expires. A summary of the PPA, including estimated average amounts for 2008 through 2012, are shown in the table below. The total cost estimates are based on projected mWh purchase volumes at PPA rates, plus estimates of VYNPC costs, primarily net interest expense and the cost of capital. Actual amounts may differ.

	2008	**Estimated Average 2009 - 2012**
Average capacity acquired	175 MW	175 MW
Share of VYNPC entitlement	34.83%	34.83%
Annual energy charge per mWh	$41.16	$43.29
Average total cost per mWh	$41.80	$43.79
Contract period termination		March 13, 2012

We normally purchase replacement energy in the wholesale markets in New England when the Vermont Yankee plant is not operating or is operating at reduced levels. We typically enter into forward purchase contracts for replacement power during scheduled refueling outages, and account for those contracts as derivatives.

We had forced outage insurance to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experienced unplanned outages between January 1 and December 31, 2007. The coverage applied to unplanned outages of up to 30 consecutive calendar days per outage event, and provided for payment of the difference between the spot market price and $40/mWh. The total maximum coverage was $10.0 million, with a $1.0 million total deductible. There was a two-day unplanned outage at the plant in the third quarter of 2007 but no claims were made under the insurance contract because the incremental replacement power cost was below the $1.0 million deductible.

In July 2007 we purchased outage insurance coverage for 2008 with similar terms to the outage insurance in place for 2007. The total maximum coverage is $12.0 million, with a $1.2 million total deductible.

On September 13, 2007, the PSB issued an Order approving a March 16, 2006 settlement proposal reached by CVPS, Green Mountain Power, ENVY and the Vermont Department of Public Service ("DPS") that resolves issues raised in a petition before the PSB regarding the Rate Payer Protection Proposal (outage protection related to the plant uprate). The PSB Order was subject to a 30-day appeal period, which ended on October 15, 2007 without appeal. We received settlement proceeds from ENVY of $1.5 million after the appeal period ended. The settlement proceeds did not have an income statement impact because a portion was recorded as a regulatory liability for return to retail customers, and the remaining offset an existing receivable.

We are a party to a PSB Docket that was opened in June 2006 to investigate whether the reliability of the increased plant output will be adversely affected by the operation of the plant's steam dryer. On September 18, 2006, the PSB issued an order requiring ENVY to provide additional ratepayer protections that would protect Vermont utilities and ratepayers if the plant is forced to reduce output because of uprate-related steam dryer problems. The DPS and ENVY reached an agreement in a compliance filing with the PSB, which will provide protections in the event of a steam dryer-related derate. The protections apply to incremental replacement power costs and would remain in effect for at least two months after therefueling outage during which the plant operates successfully with no steam dryer-related outages or derates. ENVY requested reconsideration of the PSB ruling. Reconsideration was denied and ENVY has appealed to the Vermont Supreme Court. Although the appeal remains pending, the period during which the protection applied in the event of a steam dryer-related derate has expired without occurrence of such an event.

The PPA between ENVY and VYNPC contains a formula for determining the VYNPC power entitlement following the uprate. VYNPC and ENVY are seeking to resolve certain differences in the interpretation of the formula. At issue is how much capacity and energy VYNPC Sponsors receive under the PPA following the uprate. Based on VYNPC's calculations the VYNPC Sponsors should be entitled to slightly more capacity and energy than they are currently receiving under the PPA. We cannot predict the outcome of this matter at this time.

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose the economic benefit of an energy volume equal to close to 50 percent of our total committed supply and have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2007, the incremental replacement cost of lost power, including capacity, is estimated to average $57.7 million annually. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to any such shutdown. However, an early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion.

Hydro-Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO is a group of Vermont electric companies, municipal utilities and cooperatives, including us. The VJO Power Contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between us and Hydro-Quebec, which altered the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO contract runs through 2020, but our purchases under the contract end in 2016.

There are specific contractual provisions providing that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2007, our obligation is about 47 percent of the total VJO Power Contract through 2016, which represents approximately $487.0 million, on a nominal basis.

In accordance with FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"), we are required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. With regard to the "step-up" provision in the VJO Power Contract, we must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. We believe this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power in their most recent rate applications. Despite the remote chance that such an event could occur, we estimate that our undiscounted purchase obligation would be about an additional $570.0 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2008 and remained in default for the duration of the contract. In such a scenario, we would then own the power and could seek to recover our costs from the defaulting members or our retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

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, we negotiated a third sellback arrangement whereby we received a reduction in capacity costs from 1995 to 1999. In exchange, Hydro-Quebec obtained two options. The first gives Hydro-Quebec the right, upon four years' written notice, to reduce capacity and associated energy deliveries by 50 MW, including the use of a like amount of our Phase I/II transmission facility rights. The second gives Hydro-Quebec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Quebec. This second option can be exercised five times through October 2015. Hydro-Quebec has not yet exercised these options. We have determined that the first option is a derivative, but the second is not because it is contingent upon a physical variable.

Under the VJO Power Contract, the VJO had elections to change the annual load factor from 75 percent to between 70 and 80 percent five times through 2020, while Hydro-Quebec had elections to reduce the load factor to not less than 65 percent three times during the same period. Hydro-Quebec and the VJO have used all of their elections. Based on elections made by the VJO in 2005 and 2006, purchases under the VJO Power Contract were at an 80 percent load factor for the contract years beginning November 1, 2005 and 2006. As of November 1, 2007, the annual load factor is 75 percent for the remainder of the contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described above.

Total purchases from Hydro Quebec were $64.9 million in 2007, $64.3 million in 2006 and $58.4 million in 2005. A summary of the Hydro-Quebec contracts, including historic and projected charges for the years indicated is shown in the table below. Projections are based on certain assumptions including availability of the transmission system and scheduled deliveries, so actual amounts may differ.

(dollars in thousands, except per kWh amounts):

	2007	Estimated Average 2008 - 2012	Estimated Average 2013 - 2016
Annual Capacity Acquired	**143.2MW**	144.8MW	(a)
Minimum Energy Purchase - annual load factor	**(b)**	75%	75%
Energy Charge	**$30,540**	$31,326	$20,968
Capacity Charge	**34,329**	33,203	20,130
Total Energy and Capacity Charge	**$64,869**	$64,529	$41,098
Average Cost per kWh	**$0.065**	$0.068	$0.071

(a) Annual capacity acquired is projected to average approximately 116 MW for 2013 - 2014, 100 MW for 2015 and 19 MW for 2016.
(b) Annual load factor was 80 percent for January thru October, and 75% for November thru December.

Independent Power Producers: We receive power from several Independent Power Producers ("IPPs"). These plants primarily use water and biomass as fuel. Most of the power comes through a state-appointed purchasing agent, VEPP Inc., which allocates power to all Vermont utilities under PSB rules. The cost of power purchases from IPPs has been reduced since mid 2003 based on a PSB-approved settlement reached by us, other parties and the DPS. The settlement was related to various legal proceedings and negotiations that began in 1999 to change the IPPs' contracts with VEPP Inc. to reduce power costs for customers' benefit. Our share of the savings, exclusive of savings that might result from implementation of IPP contract buy downs through securitization, are expected to range from $0.2 million to $0.5 million annually for the years 2008 through 2012. In 2007, total purchased power from IPPs amounted to $22.8 million, representing approximately 6 percent of total mWh purchased and 14 percent of total purchased power expense. Total purchased power from IPPs was $24.0 million in 2006 and $19.7 million in 2005. Estimated annual purchases are expected to range from $21.7 million to $22.5 million for 2008 and 2012. These estimates are based on assumptions regarding average weather conditions and other factors affecting generating unit output, so actual amounts may differ.

Joint-ownership We have joint-ownership interests in electric generating and transmission facilities that are included in Utility Plant on our Consolidated Balance Sheets. These include:

	Fuel Type	Ownership	Date In Service	MW Entitlement
Wyman #4	Oil	1.7769%	1978	10.8
Joseph C. McNeil	Various	20.0000%	1984	10.8
Millstone Unit #3	Nuclear	1.7303%	1986	20.0
Highgate Transmission Facility		47.5200%	1985	N/A

At December 31 our share of these facilities was (dollars in thousands):

	2007			2006		
	Gross Investment	**Accumulated Depreciation**	**Net Investment**	Gross Investment	Accumulated Depreciation	Net Investment
Wyman #4	**$3,504**	**$2,817**	**$687**	$3,422	$2,719	$703
Joseph C. McNeil	**15,587**	**11,762**	**3,825**	15,555	11,234	4,321
Millstone Unit #3	**77,349**	**39,322**	**38,027**	77,162	39,048	38,114
Highgate Transmission Facility	**14,390**	**8,332**	**6,058**	14,357	7,985	6,372
	$110,830	**$62,233**	**$48,597**	$110,496	$60,986	$49,510

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

In 2005, Millstone Unit #3's operating license was extended from November 2025 to November 2045. In October 2007, DNC filed with the NRC for a 7 percent power uprate of the plant. This would increase our share of plant generation by 1.4 MW, and we would be obligated to pay our ownership share of the related costs. In January 2004, DNC filed, on behalf of itself and the two minority owners, including us, a lawsuit against the DOE seeking recovery of costs related to storage of spent nuclear fuel arising from the failure of the DOE to comply with its obligations to commence accepting such fuel in 1998. A trial is expected to be held in August 2008. We continue to pay our share of the DOE Spent Fuel assessment expenses levied on actual generation and will share in recovery from the lawsuit, if any, in proportion to our ownership interest.

Performance Assurance At December 31, 2007, we had posted $6.4 million of collateral under performance assurance requirements for certain of our power contracts, including $6.0 million of letters of credit issued under our $25.0 million revolving credit facility, $0.3 million was in cash and $0.1 million was represented by restricted cash.

We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy for NEPOOL members. We are required to post collateral for all net purchased power transactions since our credit limit with ISO-New England is zero. At December 31, 2007, we had posted $0.3 million of cash and a $5.0 million letter of credit under our revolving credit facility.

We are currently selling power in the wholesale market pursuant to contracts with third parties, and are required to post collateral under certain conditions defined in the contracts. At December 31, 2007, we had posted $1.0 million in the form of a letter of credit, and $0.1 million of restricted cash.

We are also subject to performance assurance requirements under our Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If ENVY, the seller, has commercially reasonable grounds to question our ability to pay for our monthly power purchases, ENVY may ask VYNPC and VYNPC may then ask us to provide adequate financial assurance of payment. We have not had to post collateral under this contract.

At December 31, 2006, we had posted $8.6 million of collateral under performance assurance requirements for certain of our power contracts, including a $4.5 million letter of credit.

Environmental Over the years, more than 100 companies have merged into or been acquired by CVPS. At least two of those companies used coal to produce gas for retail sale. This practice ended more than 50 years ago. Gas manufacturers, their predecessors and CVPS used waste disposal methods that were legal and acceptable then, but may not meet modern environmental standards and could represent a liability. Some operations and activities are inspected and supervised by federal and state authorities, including the Environmental Protection Agency. We believe that we are in compliance with all laws and regulations and have implemented procedures and controls to assess and assure compliance. Corrective action is taken when necessary. Below is a brief discussion of known material issues.

Cleveland Avenue Property: The Cleveland Avenue property in Rutland, Vermont, was used by a predecessor to make gas from coal. Later, we sited various operations there. Due to the existence of coal tar deposits, polychlorinated biphenyl contamination and the potential for off-site migration, we conducted studies in the late 1980s and early 1990s to quantify the potential costs to remediate the site. Investigation at the site has continued, including work with the State of Vermon t to develop a mutually acceptable solution. In 2006, we updated the cost estimate of remediation for this site. The liability for site remediation is expected to range from $2.3 million to $0.9 million. As of December 31, 2007, we accrued $1.3 million representing the most likely cost of the remediation effort.

Brattleboro Manufactured Gas Facility: In the 1940s, we owned and operated a manufactured gas facility in Brattleboro, Vermont. We ordered a site assessment in 1999 at the request of the State of New Hampshire. In 2001, New Hampshire indicated that no further action was required, though it reserved the right to require further investigation or remedial measures. In 2002, the Vermont Agency of Natural Resources notified us that our corrective action plan for the site was approved. That plan is now in place. In 2006, we updated the cost estimate of remediation for this site. The liability for site remediation is expected to range from $1.3 million to $0.1 million. As of December 31, 2007, we accrued $0.6 million representing the most likely cost of the remediation effort.

Dover, New Hampshire, Manufactured Gas Facility: In 1999, Public Service Company of New Hampshire ("PSNH") contacted us about this site. PSNH alleged that we were partially liable for cleanup, since the site was previously operated by Twin State Gas and Electric, which merged into CVPS on the same day that PSNH bought the facility. In 2002, we reached a settlement with PSNH in which certain liabilities we might have had were assigned to PSNH in return for a cash settlement paid by CVPS based on completion of PSNH's cleanup effort. Our remaining obligation was less than $0.1 million at December 31, 2007.

The reserve for environmental matters described above amounted to $1.9 million as of December 31, 2007 and $2.1 million as of December 31, 2006. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets. The reserve represents our best estimate of the cost to remedy issues at these sites based on available information as of the end of the reporting periods. To management's knowledge, there is no pending or threatened litigation regarding other sites with the potential to cause material expense. No government agency has sought funds from us for any other study or remediation.

Leases and support agreements

Capital Leases: We had obligations under capital leases of $6.8 million at December 31, 2007 and $7.5 million at December 31, 2006. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets, and are offset by Property under capital leases included in Utility plant. We account for capital leases under SFAS No. 13, *Accounting for Leases*. In accordance with SFAS No. 71 and based on our ratemaking treatment, amortizations of leased assets are recorded as operating expenses on the income statement, depending on the nature and function of the leased assets. Of the $6.8 million, $6.6 million is related to the Phase II Hydro-Quebec ("Phase II") transmission facilities and the remaining $0.2 million is related to several five-year office equipment leases.

We participated with other electric utilities in the construction of the Phase II Hydro-Quebec ("Phase II") transmission facilities in New England, which were completed at a total initial cost of $487 million. Under a 30-year support agreement relating to participation in the facilities, we agreed to pay our 5.132 percent share of Phase II costs, including capital costs plus the costs of owning and operating the facilities, over a 25-year recovery period that ends in 2015, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2020. Approximately $30.0 million of additional investments have been made to the Phase II transmission facilities since they were initially constructed. All costs under these agreements are recorded as transmission expense in accordance with our ratemaking policies. At December 31, 2007, the $6.6 million unamortized balance was comprised of $19.1 million related to our share of original costs and additional investments, offset by $12.5 million of accumulated amortization.

We also participated with other electric utilities in the construction of the Phase I Hydro-Quebec ("Phase I") transmission facilities in northeastern Vermont and northern New Hampshire, which were completed at a total cost of $140.0 million. Under the 30-year support agreement relating to participation in the facilities, we were obligated to pay our 4.55 percent share of Phase I capital costs over a 20-year recovery period that ended in 2006, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2016. At December 31, 2007, we had recorded accumulated amortizations of $4.9 million representing our share of the original costs associated with the Phase I transmission facility.

The Phase I and Phase II support agreements provide options for extending the agreements an additional 20 years. Each option must be exercised two years before each agreement terminates, and the transmission facilities for Phase I and Phase II must operate simultaneously for the interconnection to operate, therefore both agreements would need to be extended to be operative. Future annual payments relating to the Phase I and Phase II transmission facilities are expected to decline from $3.1 million in 2008 to $2.2 million in 2016. If we elect to extend both agreements, annual payments are expected to increase during the renewal terms. Approximately $0.6 million of the annual costs are reimbursed to us pursuant to the New England Power Pool Open Access Transmission Tariff.

For the year ended December 31, 2007, imputed interest on capital leases totaled $0.6 million. A summary of minimum lease payments as of December 31, 2007 follows (dollars in thousands).

Year	Capital Leases
2008	$1,449
2009	1,374
2010	1,300
2011	1,185
2012	1,083
Thereafter	2,676
Future minimum lease payments	9,067
Less: amount representing interest	2,279
Present value of net minimum lease payments	$6,788

Operating Leases: We lease our vehicles and related equipment under one operating lease agreement. The individual leases are mutually cancelable one year from lease inception. We have the ability to lease vehicles and related equipment up to an aggregate unamortized balance of $13.0 million, of which $9.9 million was outstanding at December 31, 2007 and $6.6 million was outstanding at December 31, 2006.

Under the terms of the vehicle operating lease, we have guaranteed a residual value to the lessor in the event the leased items are sold. The guarantee provides for reimbursement of up to 87 percent of the unamortized value of the lease portfolio. Under the guarantee, if the entire lease portfolio had a fair value of zero at December 31, 2007, we would have been responsible for a maximum reimbursement of $8.6 million. We had a liability of $0.2 million at December 31, 2007 included in other current liabilities representing our obligation under the guarantee based on the fair market value of the entire portfolio, and this amount is offset by $0.2 million of prepayments.

The lease agreement also contains a contingent rental provision based on the sale proceeds of any equipment being less than the non-guaranteed portion of the base amount because of abuse, damage, extraordinary wear and tear or excessive usage. The total amount due to the lessor for any equipment sold will not exceed the unamortized balance of such equipment.

From 1999 to 2002, SmartEnergy Water Heating Services, Inc. leased certain of the water heater tanks that it rents to customers under a master lease agreement. The lease terms are non-cancelable except in the general case of loss, destruction, unrepairable damage, customer termination or obsolescence. The lease is secured by essentially all of the assets of SmartEnergy Water Heating Services, Inc. and is guaranteed by Eversant. Our estimated maximum exposure under the master lease agreement is a potential payment due in the event of unrepairable damage, loss or destruction to the tanks of approximately $0.1 million. At December 31, 2007, the unamortized balance under this lease was $0.1 million.

Other operating lease commitments are considered minimal, as most are cancelable after one year from inception or the future minimum lease payments are of a nominal amount. At December 31, 2007, future minimum rental payments required under non-cancelable leases are expected to total $0.3 million over the next five years, and annual minimum rental payments after that time are of a nominal amount.

Total rental expense, which includes pole attachment rents in addition to the operating lease agreements described above, amounted to $6.8 million in 2007, $6.0 million in 2006, and $5.5 million in 2005. These are included in Other operation on the Consolidated Statements of Income.

Reserve for Loss on Power Contract On January 1, 2004, we terminated a long-term power contract with Connecticut Valley Electric Company, a regulated electric utility that was a wholly owned subsidiary of the company. In accordance with the requirements of SFAS No. 5, *Accounting for Contingencies ("SFAS No. 5")*, we recorded a $14.4 million pre-tax loss accrual in the first quarter of 2004 related to the contract termination. The loss accrual represented our best estimate of the difference between expected future sales revenue, in the wholesale market, for the purchased power that was formerly sold to Connecticut Valley Electric Company and the net cost of purchased power obligations. We review this estimate at the end of each reporting period and will increase the reserve if the revised estimate exceeds the recorded loss accrual. The loss accrual is being amortized on a straight-line basis through 2015, the estimated life of the power contracts that were in place to supply power under the contract.

Catamount Indemnifications Under the terms of the agreements with Catamount and Diamond Castle, we agreed to indemnify them, and certain of their respective affiliates, in respect of a breach of certain representations and warranties and covenants, most of which ended June 30, 2007, except certain items that customarily survive indefinitely. Indemnification is subject to a $1.5 million deductible and a $15.0 million cap, excluding certain customary items. Environmental representations are subject to the deductible and the cap, and such environmental representations for only two of Catamount's underlying energy projects survived beyond June 30, 2007. Our estimated "maximum potential" amount of future payments related to these indemnifications is limited to $15.0 million. We have not recorded any liability related to these indemnifications.

Legal Proceedings We are involved in legal and administrative proceedings in the normal course of business. We do not believe that the ultimate outcome of these proceedings will have a material adverse effect on our financial position, results of operations or cash flows.

Appropriated Retained Earnings Major hydroelectric project licenses provide that after an initial 20-year period, a portion of the earnings of such project in excess of a specified rate of return is to be set aside in appropriated retained earnings in compliance with FERC Order No. 5, issued in 1978. Appropriated retained earnings included in retained earnings on the Consolidated Balance Sheets were $0.8 million at December 31, 2007 and 2006.

NOTE 17 - SEGMENT REPORTING

Our reportable operating segments include: **Central Vermont Public Service Corporation ("CV - VT")**, which engages in the purchase, production, transmission, distribution and sale of electricity in Vermont; Custom Investment Corporation and East Barnet are included with CV- VT in the table below; **Other Companies** include Catamount Resources Corporation ("CRC"), Eversant Corporation, ("Eversant"), and C.V. Realty, Inc. CRC was formed to hold our subsidiaries that invest in unregulated business opportunities and is the parent company of Eversant, which engages in the sale and rental of electric water heaters in Vermont and New Hampshire through its wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. C.V. Realty, Inc. is a real estate company whose purpose is to own, acquire, buy, sell and lease real and personal property and interests.

The accounting policies of operating segments are the same as those described in Note 1 - Business Organization and Summary of Significant Accounting Policies. Segment profit or loss is based on profit or loss from continuing operations after income taxes and preferred stock dividends. Other Companies are below the quantitative thresholds individually and in the aggregate; therefore, we have revised the table below to report all of our other companies as an operating segment, including prior years. Inter-segment revenues are excluded from the table below and are less than $12,000 for each period. Financial information follows (dollars in thousands):

2007	CV VT	Other Companies	Reclassification and Consolidating Entries	Consolidated
Revenues from external customers	**$329,107**	**$1,798**	**$(1,798)**	**$329,107**
Depreciation and amortizations (a)	**10,993**	**184**	**(184)**	**10,993**
Operating income tax expense	**5,291**	**329**	**(329)**	**5,291**
Equity in earnings of affiliates	**6,430**	**-**	**-**	**6,430**
Interest income (b)	**587**	**58**	**-**	**645**
Interest expense	**8,475**	**47**	**-**	**8,522**
Income from continuing operations	**15,317**	**487**	**-**	**15,804**
Investments in affiliates	**93,452**	**-**	**-**	**93,452**
Total assets	**538,481**	**2,134**	**(301)**	**540,314**
Construction and plant expenditures (c)	**23,663**	**250**	**-**	**23,913**

2006				
Revenues from external customers	$325,738	$1,838	$(1,838)	$325,738
Depreciation and amortizations (a)	14,240	175	(175)	14,240
Operating income tax expense	8,569	284	(284)	8,569
Equity in earnings of affiliates	3,240	-	-	3,240
Interest income (b)	1,386	728	-	2,114
Interest expense	8,231	-	-	8,231
Income from continuing operations	17,074	1,027	-	18,101
Investments in affiliates	39,339	-	-	39,339
Total assets	499,125	2,314	(501)	500,938
Construction and plant expenditures (c)	23,810	208	-	24,018
2005				
Revenues from external customers	$311,359	$1,847	$(1,847)	$311,359
Depreciation and amortizations (a)	13,300	174	(174)	13,300
Operating income tax (benefit) expense	(2,264)	304	(304)	(2,264)
Equity in earnings of affiliates	1,869	-	-	1,869
Interest income (b)	1,144	347	(249)	1,242
Interest expense	9,493	248	(248)	9,493
Income from continuing operations (d)	1,290	120	-	1,410
Investments in affiliates	15,801	-	-	15,801
Total assets	496,483	60,604	(5,654)	551,433
Construction and plant expenditures	17,558	-	-	17,558

(a) Includes net deferral and amortization of nuclear replacement energy and maintenance costs, and amortization of regulatory assets and liabilities. These items are included in Purchased Power and Other Operation, respectively, on the Consolidated Statements of Income. Also includes capital lease amortizations.
(b) Included in Other Income on the Consolidated Statements of Income.
(c) Construction and plant expenditures for Other Companies are included in other investing activities on the Consolidated Statements of Cash Flows.
(d) Includes a $21.8 million pre-tax charge related to a March 29, 2005 PSB-approved Rate Order.

NOTE 18 - UNAUDITED QUARTERLY FINANCIAL INFORMATION

The amounts included in the table below are in thousands, except per share amounts:

	Quarter Ended				
	March	June	September	December	Total (a)
2007					
Operating revenues	**$86,696**	**$77,380**	**$79,174**	**$85,857**	**$329,107**
Utility operating income	**$6,063**	**$887**	**$5,147**	**$5,878**	**$17,975**
Net income	**$5,706**	**$521**	**$4,321**	**$5,256**	**$15,804**
Basic earnings per share	**$0.55**	**$0.04**	**$0.41**	**$0.51**	**$1.52**
Diluted earnings per share	**$0.55**	**$0.04**	**$0.41**	**$0.50**	**$1.49**
2006					
Operating revenues	$82,255	$78,992	$79,912	$84,579	$325,738
Utility operating income	$4,620	$2,238	$7,788	$6,677	$21,323
Income from continuing operations	$4,097	$995	$7,004	$6,005	$18,101
Income from discontinued operations	-	-	-	251	251
Net income	$4,097	$995	$7,004	$6,256	$18,352
Basic earnings per share - continuing operations	$0.33	$0.08	$0.67	$0.58	$1.65
Basic earnings per share - discontinued operations	-	-	-	0.02	0.02
Total basic earnings per share	$0.33	$0.08	$0.67	$0.60	$1.67
Diluted earnings per share - continuing operations	$0.32	$0.08	$0.66	$0.57	$1.64
Diluted earnings per share - discontinued operations	-	-	-	0.02	0.02
Total diluted earnings per share	$0.32	$0.08	$0.66	$0.59	$1.66

(a) The summation of quarterly earnings per share data may not equal annual data due to rounding.

NOTE 19 - SUBSEQUENT EVENTS
Retail Rates: As described in Note 7 - Retail Rates and Regulatory Accounting, on January 31, 2008, the PSB approved a settlement agreement that we reached with the DPS regarding our May 15, 2007 request for a rate increase.

Notes Payable: As described in Note 13 - Notes Payable and Credit Facility, we have the sole option to extend the maturity of our $53.0 million term note and our credit facility to March 31, 2009.

Letters of Credit: As described in Note 12 - Long-Tem Debt, pursuant to a bank commitment dated March 10, 2008, we have the sole option to extend the maturity of $16.9 million of letters of credit to November 30, 2009.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Management of the company, under the supervision and with participation of our Chief Executive Officer and Principal Financial and Accounting Officer, conducted an evaluation of the effectiveness of the design and operation of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")), as of December 31, 2007. Based on this evaluation, our Chief Executive Officer and Principal Financial and Accounting Officer concluded that, as of December 31, 2007, the company's disclosure controls and procedures are effective.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Securities and Exchange Act of 1934. The company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and of the preparation and fair presentation of the Company's financial statements for external reporting purposes in accordance with generally accepted accounting principles.

Under the supervision of our Chief Executive Officer and Principal Financial and Accounting Officer, and with participation of management, we assessed the effectiveness of the company's internal control over financial reporting based on the framework established in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, we have concluded that the company's internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by Deloitte & Touche LLP, the independent registered public accounting firm that audited our consolidated financial statements, whose report is included below.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Central Vermont Public Service Corporation

We have audited the internal control over financial reporting of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule as of and for the year ended December 31, 2007 of the Company and our report dated March 11, 2008, which report also refers to the reports of other auditors, expresses an unqualified opinion on those financial statements and includes explanatory paragraphs relating to the adoption of Statement of Financial Accounting Standard No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*, and Financial Accounting Standards Board ("FASB") Interpretation 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*.

/s/ Deloitte & Touche LLP

Philadelphia, Pennsylvania
March 11, 2008

<u>Item 9B. Other Information</u>
None

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the section entitled "Director Elections" of the Proxy Statement of the Company for the 2008 Annual Meeting of Stockholders. The Executive Officers information is listed under Part I, Item 1. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 28, 2008.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the section entitled "Summary Compensation Table" of the Proxy Statement of the Company for the 2008 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 28, 2008.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item related to security ownership of certain beneficial owners is incorporated herein by reference to the section entitled "Security Ownership of Certain Beneficial Owners and Management" of the Proxy Statement of the Company for the 2008 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 28, 2008.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the sections entitled "Certain Relationships and Related Transactions" and "Board Independence" of the Proxy Statement of the Company for the 2008 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 28, 2008.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the sections entitled "Services Performed by the Independent Registered Public Accountants" and "Independent Registered Public Accountant Fees" of the Proxy Statement of the Company for the 2008 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 28, 2008.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)1. The following financial statements are included herein under Part II, Item 8, financial Statements and Supplementary Data:

Consolidated Statements of Income for the three years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Comprehensive Income for the three years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Cash Flows for the three years ended December 31, 2007, 2006 and 2005

Consolidated Balance Sheets at December 31, 2007 and 2006

Consolidated Statements of Changes in Common Stock Equity at December 31, 2007, 2006 and 2005

Notes to Consolidated Financial Statements

(a)2. Schedule II - Reserves for the three years ended December 31, 2007, 2006 and 2005

(a)3. Exhibits (* denotes filed herewith)

Each document described below is incorporated by reference to the appropriate exhibit numbers and the Commission file numbers indicated in parentheses, unless the reference to the document is marked as follows:

* - Filed herewith.

Copies of any of the exhibits filed with the Securities and Exchange Commission in connection with this document may be obtained from the Company upon written request.

Exhibit 3 Articles of Incorporation and Bylaws

3-1 By-laws, as amended October 8, 2005. (Exhibit 99.2, Current Report on Form 8-K Filed October 11, 2005, File No. 1-8222)

3-2 Articles of Association, as amended August 11, 1992. (Exhibit No. 3-2, 1992 10-K, File No. 1-8222)

Exhibit 4 Instruments defining the rights of security holders, including Indentures

Incorporated herein by reference:

4-1 Bond Purchase Agreement between Merrill, Lynch, Pierce, Fenner & Smith, Inc., Underwriters and The Industrial Development Authority of the State of New Hampshire, issuer and Central Vermont Public Service Corporation. (Exhibit B-46, 1984 Form 10-K, File No. 1-8222)

4-2 Bond Purchase Agreement among Connecticut Development Authority and Central Vermont Public Service Corporation with E. F. Hutton & Company Inc. dated December 11, 1985. (Exhibit B-48, 1985 Form 10-K, File No. 1-8222)

4-3 Stock-Purchase Agreement between Vermont Electric Power Company, Inc. and the Company dated August 11, 1986 relative to purchase of Class C Preferred Stock. (Exhibit B-49, 1986 Form 10-K, File No. 1-8222)

4-4 Forty-Fourth Supplemental Indenture, dated as of June 15, 2004 amending and restating the Company's Indenture of Mortgage dated as of October 1, 1929. (Exhibit 4-63, Form 10-Q, June 30, 2004, File No. 1-8222)

4-5 Forty-Fifth Supplemental Indenture, dated as of July 15, 2004 and directors' resolutions establishing the Series SS and Series TT Bonds and matter connected therewith. (Exhibit 4-64, Form 10-Q, June 30, 2004, File No. 1-8222)

4-6 Form of Bond Purchase Agreement dated as of July 15, 2004 relating to Series SS and Series TT Bonds. (Exhibit 4-65, Form 10-Q, June 30, 2004, File No. 1-8222)

Exhibit 10 Material Contracts (* Denotes filed herewith)

Incorporated herein by reference:

10.1 Copy of firm power Contract dated August 29, 1958, and supplements thereto dated September 19, 1958, October 7, 1958, and October 1, 1960, between the Company and the State of Vermont (the "State"). (Exhibit C-1, File No. 2-17184)

10.1.1 Agreement setting out Supplemental NEPOOL Understandings dated as of April 2, 1973. (Exhibit C-22, File No. 5-50198)

10.2 Copy of Transmission Contract dated June 13, 1957, between Velco and the State, relating to transmission of power. (Exhibit 10.2, 1993 Form 10-K, File No. 1-8222)

10.2.1 Copy of letter agreement dated August 4, 1961, between Velco and the State. (Exhibit C-3, File No. 2-26485)

10.2.2 Amendment dated September 23, 1969. (Exhibit C-4, File No. 2-38161)

10.2.3 Amendment dated March 12, 1980. (Exhibit C-92, 1982 Form 10-K, File No. 1-8222)

10.2.4 Amendment dated September 24, 1980. (Exhibit C-93, 1982 Form 10-K, File No. 1-8222)

10.3 Copy of subtransmission contract dated August 29, 1958, between Velco and the Company (there are seven similar contracts between Velco and other utilities). (Exhibit 10.3, 1993 Form 10-K, Form No. 1-8222)

10.3.1 Copies of Amendments dated September 7, 196l, November 2, 1967, March 22, 1968, and October 29, 1968. (Exhibit C-6, File No. 2-32917)

10.3.2 Amendment dated December 1, 1972. (Exhibit 10.3.2, 1993 Form 10-K, File No. 1-8222)

10.4 Copy of Three-Party Agreement dated September 25, 1957, between the Company, Green Mountain and Velco. (Exhibit C-7, File No. 2-17184)

10.4.1 Superseding Three Party Power Agreement dated January 1, 1990. (Exhibit 10-201, 1990 Form 10-K, File No. 1-8222)

10.4.2 Agreement Amending Superseding Three Party Power Agreement dated May 1, 1991. (Exhibit 10.4.2, 1991 Form 10-K, File No. 1-8222)

10.4.3 Amended and Restated Three-Party Agreement between the Company, Green Mountain Power Corporation, Vermont Electric Power Company, Inc., and Vermont Transco, LLC effective June 30, 2006. (Exhibit 10.4.3, 2006 Form 10-K, File No. 1-8222)

10.5 Copy of firm power Contract dated December 29, 1961, between the Company and the State, relating to purchase of Niagara Project power. (Exhibit C-8, File No. 2-26485)

10.5.1 Amendment effective as of January 1, 1980. (Exhibit 10.5.1, 1993 Form 10-K, File No. 1-8222)

10.6 Copy of agreement dated July 16, 1966, and letter supplement dated July 16, 1966, between Velco and Public Service Company of New Hampshire relating to purchase of single unit power from Merrimack II. (Exhibit C-9, File No. 2-26485)

10.6.1 Copy of Letter Agreement dated July 10, 1968, modifying Exhibit A. (Exhibit C-10, File No. 2-32917)

10.7 Copy of Capital Funds Agreement between the Company and Vermont Yankee dated as of February 1, 1968. (Exhibit C-11, File No. 70-4611)

10.7.1 Copy of Amendment dated March 12, 1968. (Exhibit C-12, File No. 70-4611)

10.7.2 Copy of Amendment dated September 1, 1993. (Exhibit 10.7.2, 1994 Form 10-K, File No. 1-8222)

10.8 Copy of Power Contract between the Company and Vermont Yankee dated as of February 1, 1968. (Exhibit C-13, File No. 70-4591)

10.8.1 Amendment dated April 15, 1983. (10.8.1, 1993 Form 10-K, File No. 1-8222)

10.8.2 Copy of Additional Power Contract dated February 1, 1984. (Exhibit C-123, 1984 Form 10-K, File No. 1-8222)

10.8.3 Amendment No. 3 to Vermont Yankee Power Contract, dated April 24, 1985. (Exhibit 10-144, 1986 Form 10-K, File No. 1-8222)

10.8.4 Amendment No. 4 to Vermont Yankee Power Contract, dated June 1, 1985. (Exhibit 10-145, 1986 Form 10-K, File No. 1-8222)

10.8.5 Amendment No. 5 dated May 6, 1988. (Exhibit 10-179, 1988 Form 10-K, File No. 1-8222)

10.8.6 Amendment No. 6 dated May 6, 1988. (Exhibit 10-180, 1988 Form 10-K, File No. 1-8222)

10.8.7 Amendment No. 7 dated June 15, 1989. (Exhibit 10-195, 1989 Form 10-K, File No. 1-8222)

10.8.8 Amendment No. 8 dated November 17, 1999. (Exhibit 10.8.8, Form 10-Q, June 30, 2000, File No. 1-8222)

10.8.9 Amendment No. 9 dated November 17, 1999. (Exhibit 10.8.9, Form 10-Q, June 30, 2000, File No. 1-8222)

10.8.10 2001 Amendatory Agreement dated as of September 21, 2001 to which the Company is a party re: Vermont Yankee Nuclear Power Corporation Power Contract. (Exhibit 10.8.10, Form 10-Q, September 30, 2001, File No. 1-8222)

10.9 Copy of Capital Funds Agreement between the Company and Maine Yankee dated as of May 20, 1968. (Exhibit C-14, File No. 70-4658)

10.9.1 Amendment No. 1 dated August 1, 1985. (Exhibit C-125, 1984 Form 10-K, File No. 1-8222)

10.10 Copy of Power Contract between the Company and Maine Yankee dated as of May 20, 1968. (Exhibit C-15, File No. 70-4658)

10.10.1 Amendment No. 1 dated March 1, 1984. (Exhibit C-112, 1984 Form 10-K, File No. 1-8222)

10.10.2 Amendment No. 2 effective January 1, 1984. (Exhibit C-113, 1984 Form 10-K, File No. 1-8222)

10.10.3 Amendment No. 3 dated October 1, 1984. (Exhibit C-114, 1984 Form 10-K, File No. 1-8222)

10.10.4 Additional Power Contract dated February 1, 1984. (Exhibit C-126, 1985 Form 10-K, File No. 1-8222)

10.11 Copy of Agreement dated January 17, 1968, between Velco and Public Service Company of New Hampshire relating to purchase of additional unit power from Merrimack II. (Exhibit C-16, File No. 2-32917)

10.12 Copy of Agreement dated February 10, 1968 between the Company and Velco relating to purchase by Company of Merrimack II unit power. (There are 25 similar agreements between Velco and other utilities.) (Exhibit C-17, File No. 2-32917)

10.13 Copy of Three-Party Power Agreement dated as of November 21, 1969, among the Company, Velco, and Green Mountain relating to purchase and sale of power from Vermont Yankee Nuclear Power Corporation. (Exhibit C-18, File No. 2-38161)

10.13.1 Amendment dated June 1, 1981. (Exhibit 10.13.1, 1993 Form 10-K, File No. 1-8222)

10.14 Copy of Three-Party Transmission Agreement dated as of November 21, 1969, among the Company, Velco, and Green Mountain providing for transmission of power from Vermont Yankee Nuclear Power Corporation. (Exhibit C-19, File No. 2-38161)

10.14.1 Amendment dated June 1, 1981. (Exhibit 10.14.1, 1993 Form 10-K, File No. 1-8222)

10.14.2 Amended and Restated Three-Party Transmission Agreement between the Company, Green Mountain Power Corporation, Vermont Electric Power Company, Inc., and Vermont Transco, LLC effective November 30, 2006. (Exhibit 10.14.2, 2006 Form 10-K, File No. 1-8222)

10.15 Copy of Stockholders Agreement dated September 25, 1957, between the Company, Velco, Green Mountain and Citizens Utilities Company. (Exhibit No. C-20, File No. 70-3558)

10.16 New England Power Pool Agreement dated as of September 1, 1971, as amended to November 1, 1975. (Exhibit C-21, File No. 2-55385)

10.16.1 Amendment dated December 31, 1976. (Exhibit 10.16.1, 1993 Form 10-K, File No. 1-8222)

10.16.2 Amendment dated January 23, 1977. (Exhibit 10.16.2, 1993 Form 10-K, File No. 1-8222)

10.16.3 Amendment dated July 1, 1977. (Exhibit 10.16.3, 1993 Form 10-K, File No. 1-8222)

10.16.4 Amendment dated August 1, 1977. (Exhibit 10.16.4, 1993 Form 10-K, File No. 1-8222)

10.16.5 Amendment dated August 15, 1978. (Exhibit 10.16.5, 1993 Form 10-K, File No. 1-8222)

10.16.6 Amendment dated January 31, 1979. (Exhibit 10.16.6, 1993 Form 10-K, File No. 1-8222)

10.16.7 Amendment dated February 1, 1980. (Exhibit 10.16.7, 1993 Form 10-K, File No. 1-8222)

10.16.8 Amendment dated December 31, 1976. (Exhibit 10.16.8, 1993 Form 10-K, File No. 1-8222)

10.16.9 Amendment dated January 31, 1977. (Exhibit 10.16.9, 1993 Form 10-K, File No. 1-8222)

10.16.10 Amendment dated July 1, 1977. (Exhibit 10.16.10, 1993 Form 10-K, File No. 1-8222)

10.16.11 Amendment dated August 1, 1977. (Exhibit 10.16.11, 1993 Form 10-K, File No. 1-8222)

10.16.12 Amendment dated August 15, 1978. (Exhibit 10.16.12, 1993 Form 10-K, File No. 1-8222)

10.16.13 Amendment dated January 31, 1980. (Exhibit 10.16.13, 1993 Form 10-K, File No. 1-8222)

10.16.14 Amendment dated February 1, 1980. (Exhibit 10.16.14, 1993 Form 10-K, File No. 1-8222)

10.16.15 Amendment dated September 1, 1981. (Exhibit 10.16.15, 1993 Form 10-K, File No. 1-8222)

10.16.16 Amendment dated December 1, 1981. (Exhibit 10.16.16, 1993 Form 10-K, File No. 1-8222)

10.16.17 Amendment dated June 15, 1983. (Exhibit 10.16.17, 1993 Form 10-K, File No. 1-8222)

10.16.18 Amendment dated September 1, 1985. (Exhibit 10-160, 1986 Form 10-K, File No. 1-8222)

10.16.19 Amendment dated April 30, 1987. (Exhibit 10-172, 1987 Form 10-K, File No. 1-8222)

10.16.20 Amendment dated March 1, 1988. (Exhibit 10-178, 1988 Form 10-K, File No. 1-8222)

10.16.21 Amendment dated March 15, 1989. (Exhibit 10-194, 1989 Form 10-K, File No. 1-8222)

10.16.22 Amendment dated October 1, 1990. (Exhibit 10-203, 1990 Form 10-K, File No. 1-8222)

10.16.23 Amendment dated September 15, 1992. (Exhibit 10.16.23, 1992 Form 10-K, File No. 1-8222)

10.16.24 Amendment dated May 1, 1993. (Exhibit 10.16.24, 1993 Form 10-K, File No. 1-8222)

10.16.25 Amendment dated June 1, 1993. (Exhibit 10.16.25, 1993 Form 10-K, File No. 1-8222)

10.16.26 Amendment dated June 1, 1994. (Exhibit 10.16.26, 1994 Form 10-K, File No. 1-8222)

10.16.27 Thirty-Second Amendment dated September 1, 1995. (Exhibit 10.16.27, Form 10-Q dated September 30, 1995, File No. 1-8222 and Exhibit 10.16.27, 1995 Form 10-K, File No. 1-8222)

10.16.28 Security Agreement dated October 7, 2003 between Central Vermont Public Service Corporation and ISO New England Inc. (Exhibit 10.16.28, Form 10-Q, September 30, 2003, File No. 1-8222)

10.17 Agreement dated October 13, 1972, for Joint Ownership, Construction and Operation of Pilgrim Unit No. 2 among Boston Edison Company and other utilities, including the Company. (Exhibit C-23, File No. 2-45990)

10.17.1 Amendments dated September 20, 1973, and September 15, 1974. (Exhibit C-24, File No. 2-51999)

10.17.2 Amendment dated December 1, 1974. (Exhibit C-25, File No. 2-54449)

10.17.3 Amendment dated February 15, 1975. (Exhibit C-26, File No. 2-53819)

10.17.4 Amendment dated April 30, 1975. (Exhibit C-27, File No. 2-53819)

10.17.5 Amendment dated as of June 30, 1975. (Exhibit C-28, File No. 2-54449)

10.17.6 Instrument of Transfer dated as of October 1, 1974, assigning partial interest from the Company to Green Mountain Power Corporation. (Exhibit C-29, File No. 2-52177)

10.17.7 Instrument of Transfer dated as of January 17, 1975, assigning a partial interest from the Company to the Burlington Electric Department. (Exhibit C-30, File No. 2-55458)

10.17.8 Addendum dated as of October 1, 1974 by which Green Mountain Power Corporation became a party thereto. (Exhibit C-31, File No. 2-52177)

10.17.9 Addendum dated as of January 17, 1975 by which the Burlington Electric Department became a party thereto. (Exhibit C-32, File No. 2-55450)

10.17.10 Amendment 23 dated as of 1975. (Exhibit C-50, 1975 Form 10-K, File No. 1-8222)

10.18 Agreement for Sharing Costs Associated with Pilgrim Unit No.2 Transmission dated October 13, 1972, among Boston Edison Company and other utilities including the Company. (Exhibit C-33, File No. 2-45990)

10.18.1 Addendum dated as of October 1, 1974, by which Green Mountain Power Corporation became a party thereto. (Exhibit C-34, File No. 2-52177)

10.18.2 Addendum dated as of January 17, 1975, by which Burlington Electric Department became a party thereto. (Exhibit C-35, File No. 2-55458)

10.19 Agreement dated as of May 1, 1973, for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units among Public Service Company of New Hampshire and other utilities, including Velco. (Exhibit C-36, File No. 2-48966)

10.19.1 Amendments dated May 24, 1974, June 21, 1974, September 25, 1974, October 25, 1974, and January 31, 1975. (Exhibit C-37, File No. 2-53674)

10.19.2 Instrument of Transfer dated September 27, 1974, assigning partial interest from Velco to the Company. (Exhibit C-38, File No. 2-52177)

10.19.3 Amendments dated May 24, 1974, June 21, 1974, and September 25, 1974. (Exhibit C-81, File No. 2-51999)

10.19.4 Amendments dated October 25, 1974 and January 31, 1975. (Exhibit C-82, File No. 2-54646)

10.19.5 Sixth Amendment dated as of April 18, 1979. (Exhibit C-83, File No. 2-64294)

10.19.6 Seventh Amendment dated as of April 18, 1979. (Exhibit C-84, File No. 2-64294)

10.19.7 Eighth Amendment dated as of April 25, 1979. (Exhibit C-85, File No. 2-64815)

10.19.8 Ninth Amendment dated as of June 8, 1979. (Exhibit C-86, File No. 2-64815)

10.19.9 Tenth Amendment dated as of October 10, 1979. (Exhibit C-87, File No. 2-66334)

10.19.10 Eleventh Amendment dated as of December 15, 1979. (Exhibit C-88, File No. 2-66492)

10.19.11 Twelfth Amendment dated as of June 16, 1980. (Exhibit C-89, File No. 2-68168)

10.19.12 Thirteenth Amendment dated as of December 31, 1980. (Exhibit C-90, File No. 2-70579)

10.19.13 Fourteenth Amendment dated as of June 1, 1982. (Exhibit C-104, 1982 Form 10-K, File No. 1-8222)

10.19.14 Fifteenth Amendment dated April 27, 1984. (Exhibit 10-134, 1986 Form 10-K, File No. 1-8222)

10.19.15 Sixteenth Amendment dated June 15, 1984. (Exhibit 10-135, 1986 Form 10-K, File No. 1-8222)

10.19.16 Seventeenth Amendment dated March 8, 1985. (Exhibit 10-136, 1986 Form 10-K, File No. 1-8222)

10.19.17 Eighteenth Amendment dated March 14, 1986. (Exhibit 10-137, 1986 Form 10-K, File No. 1-8222)

10.19.18 Nineteenth Amendment dated May 1, 1986. (Exhibit 10-138, 1986 Form 10-K, File No. 1-8222)

10.19.19 Twentieth Amendment dated September 19, 1986. (Exhibit 10-139, 1986 Form 10-K, File No. 1-8222)

10.19.20 Amendment No. 22 dated January 13, 1989. (Exhibit 10-193, 1989 Form 10-K, File No. 1-8222)

10.20 Transmission Support Agreement dated as of May 1, 1973, among Public Service Company of New Hampshire and other utilities, including Velco, with respect to New Hampshire Nuclear Units. (Exhibit C-39, File No. 2-48966)

10.21 Sharing Agreement - 1979 Connecticut Nuclear Unit dated September 1, 1973, to which the Company is a party. (Exhibit C-40, File No. 2-50142)

10.21.1 Amendment dated as of August 1, 1974. (Exhibit C-41, File No. 2-51999)

10.21.2 Instrument of Transfer dated as of February 28, 1974, transferring partial interest from the Company to Green Mountain. (Exhibit C-42, File No. 2-52177)

10.21.3 Instrument of Transfer dated January 17, 1975, transferring a partial interest from the Company to Burlington Electric Department. (Exhibit C-43, File No. 2-55458)

10.21.4 Amendment dated May 11, 1984. (Exhibit C-110, 1984 Form 10-K, File No. 1-8222)

10.22 Preliminary Agreement dated as of July 5, 1974, with respect to 1981 Montague Nuclear Generating Units. (Exhibit C-44, File No. 2-51733)

10.22.1 Amendment dated June 30, 1975. (Exhibit C-45, File No. 2-54449)

10.23 Agreement for Joint Ownership, Construction and Operation of William F. Wyman Unit No. 4 dated November 1, 1974, among Central Maine Power Company and other utilities including the Company. (Exhibit C-46, File No. 2-52900)

10.23.1 Amendment dated as of June 30, 1975. (Exhibit C-47, File No. 2-55458)

10.23.2 Instrument of Transfer dated July 30, 1975, assigning a partial interest from Velco to the Company. (Exhibit C-48, File No. 2-55458)

10.24 Transmission Agreement dated November 1, 1974, among Central Maine Power Company and other utilities including the Company with respect to William F. Wyman Unit No. 4. (Exhibit C-49, File No. 2-54449)

10.25 Copy of Power Contract between the Company and Yankee Atomic dated as of June 30, 1959. (Exhibit C-61, 1981 Form 10-K, File No. 1-8222)

- 10.25.1 Revision dated April 1, 1975. (Exhibit C-61, 1981 Form 10-K, File No. 1-8222)
- 10.25.2 Amendment dated May 6, 1988. (Exhibit 10-181, 1988 Form 10-K, File No. 1-8222)
- 10.25.3 Amendment dated June 26, 1989. (Exhibit 10-196, 1989 Form 10-K, File No. 1-8222)
- 10.25.4 Amendment dated July 1, 1989. (Exhibit 10-197, 1989 Form 10-K, File No. 1-8222)
- 10.25.5 Amendment dated February 1, 1992 (Exhibit 10.25.5, 1992 Form 10-K, File No. 1-8222)
- 10.25.6 Amendment to the Power Contract between the Company and Yankee Atomic Electric Company dated October 1, 1980. (Exhibit 10.25.6, Form 10-Q, September 30, 2006, File No. 1-8222)
- 10.25.7 Amendment No. 3 to the Power Contract between the Company and Yankee Atomic Electric Company dated April 1, 1985. (Exhibit 10.25.7, Form 10-Q, September 30, 2006, File No. 1-8222)
- 10.25.8 Amendment No. 8 to the Power Contract between the Company and Yankee Atomic Electric Company dated June 1, 2003. (Exhibit 10.25.8, Form 10-Q, September 30, 2006, File No. 1-8222)
- 10.25.9 Amendment No. 9 to the Power Contract between the Company and Yankee Atomic Electric Company dated November 17, 2005. (Exhibit 10.25.9, Form 10-Q, September 30, 2006, File No. 1-8222)
- 10.25.10 Amendment No. 10 to the Power Contract between the Company and Yankee Atomic Electric Company dated April 14, 2006. (Exhibit 10.25.10, Form 10-Q, September 30, 2006, File No. 1-8222)

10.26 Copy of Transmission Contract between the Company and Yankee Atomic dated as of June 30, 1959. (Exhibit C-63, 1981 Form 10-K, File No. 1-8222)

10.27 Copy of Power Contract between the Company and Connecticut Yankee dated as of June 1, 1964. (Exhibit C-64, 1981 Form 10-K, File No. 1-8222)

- 10.27.1 Supplementary Power Contract dated March 1, 1978. (Exhibit C-94, 1982 Form 10-K, File No. 1-8222)
- 10.27.2 Amendment dated August 22, 1980. (Exhibit C-95, 1982 Form 10-K, File No. 1-8222)
- 10.27.3 Amendment dated October 15, 1982. (Exhibit C-96, 1982 Form 10-K, File No. 1-8222)
- 10.27.4 Second Supplementary Power Contract dated April 30, 1984. (Exhibit C-115, 1984 Form 10-K, File No. 1-8222)
- 10.27.5 Additional Power Contract dated April 30, 1984. (Exhibit C-116, 1984 Form 10-K, File No. 1-8222)
- 10.27.6 1987 Supplementary Power Contract, dated as of April 1, 1987. (Exhibit 10.27.6, Form 10-Q, June 30, 2000, File No. 1-8222)
- 10.27.7 1996 Amendatory Agreement, dated December 1, 1996. (Exhibit 10.27.7, Form 10-Q, June 30, 2000, File No. 1-8222)

10.27.8 2000 Amendatory Agreement, dated May, 2000. (Exhibit 10.27.8, Form 10-Q, June 30, 2000, File No. 1-8222)

10.28 Copy of Transmission Contract between the Company and Connecticut Yankee dated as of July 1, 1964. (Exhibit C-65, 1981 Form 10-K, File No. 1-8222)

10.29 Copy of Capital Funds Agreement between the Company and Connecticut Yankee dated as of July 1, 1964. (Exhibit C-66, 1981 Form 10-K, File No. 1-8222)

10.29.1 Copy of Capital Funds Agreement between the Company and Connecticut Yankee dated as of September 1, 1964. (Exhibit C-67, 1981 Form 10-K, File No. 1-8222)

10.30 Copy of Five-Year Capital Contribution Agreement between the Company and Connecticut Yankee dated as of November 1, 1980. (Exhibit C-68, 1981 Form 10-K, File No. 1-8222)

10.31 Form of Guarantee Agreement dated as of November 7, 1981, among certain banks, Connecticut Yankee and the Company, relating to revolving credit notes of Connecticut Yankee. (Exhibit C-69, 1981 Form 10-K, File No. 1-8222)

10.32 Form of Guarantee Agreement dated as of November 13, 1981, between The Connecticut Bank and Trust Company, as Trustee, and the Company, relating to debentures of Connecticut Yankee. (Exhibit C-70, 1981 Form 10-K, File No. 1-8222)

10.33 Form of Guarantee Agreement dated as of November 5, 1981, between Bankers Trust Company, as Trustee of the Vernon Energy Trust, and the Company, relating to Vermont Yankee Nuclear Fuel Sale Agreement. (Exhibit C-71, 1981 Form 10-K, File No. 1-8222)

10.34 Preliminary Vermont Support Agreement re Quebec interconnection between Velco and among seventeen Vermont Utilities dated May 1, 1981. (Exhibit C-97, 1982 Form 10-K, File No. 1-8222)

10.34.1 Amendment dated June 1, 1982. (Exhibit C-98, 1982 Form 10-K, File No. 1-8222)

10.35 Vermont Participation Agreement for Quebec Interconnection between Velco and among seventeen Vermont Utilities dated July 15, 1982. (Exhibit C-99, 1982 Form 10-K, File No. 1-8222)

10.35.1 Amendment No. 1 dated January 1, 1986. (Exhibit C-132, 1986 Form 10-K, File No. 1-8222)

10.36 Vermont Electric Transmission Company Capital Funds Support Agreement between Velco and among sixteen Vermont Utilities dated July 15, 1982. (Exhibit C-100, 1982 Form 10-K, File No. 1-8222)

10.37 Vermont Transmission Line Support Agreement, Vermont Electric Transmission Company and twenty New England Utilities dated December 1, 1981, as amended by Amendment No. 1 dated June 1, 1982, and by Amendment No. 2 dated November 1, 1982. (Exhibit C-101, 1982 Form 10-K, File No. 1-8222)

10.37.1 Amendment No. 3 dated January 1, 1986. (Exhibit 10-149, 1986 Form 10-K, File No. 1-8222)

10.38 Phase 1 Terminal Facility Support Agreement between New England Electric Transmission Corporation and twenty New England Utilities dated December 1, 1981, as amended by Amendment No. 1 dated as of June 1, 1982 and by Amendment No. 2 dated as of November 1, 1982. (Exhibit C-102, 1982 Form 10-K, File No. 1-8222)

10.39 Power Purchase Agreement between Velco and CVPS dated June 1, 1981. (Exhibit C-103, 1982 Form 10-K, File No. 1-8222)

10.40 Agreement for Joint Ownership, Construction and Operation of the Joseph C. McNeil Generating Station by and between City of Burlington Electric Department, Central Vermont Realty, Inc. and Vermont Public Power Supply Authority dated May 14, 1982. (Exhibit C-107, 1983 Form 10-K, File No. 1-8222)

10.40.1 Amendment No. 1 dated October 5, 1982. (Exhibit C-108, 1983 Form 10-K, File No. 1-8222)

10.40.2 Amendment No. 2 dated December 30, 1983. (Exhibit C-109, 1983 Form 10-K, File No. 1-8222)

10.40.3 Amendment No. 3 dated January 10, 1984. (Exhibit 10-143, 1986 Form 10-K, File No. 1-8222)

10.41 Transmission Service Contract between Central Vermont Public Service Corporation and The Vermont Electric Generation & Transmission Cooperative, Inc. dated May 14, 1984. (Exhibit C-111, 1984 Form 10-K, File No. 1-8222)

10.42 Copy of Highgate Transmission Interconnection Preliminary Support Agreement dated April 9, 1984. (Exhibit C-117, 1984 Form 10-K, File No. 1-8222)

10.43 Copy of Allocation Contract for Hydro-Quebec Firm Power dated July 25, 1984. (Exhibit C-118, 1984 Form 10-K, File No. 1-8222)

10.43.1 Tertiary Energy for Testing of the Highgate HVDC Station Agreement, dated September 20, 1985. (Exhibit C-129, 1985 Form 10-K, File No. 1-8222)

10.44 Copy of Highgate Operating and Management Agreement dated August 1, 1984. (Exhibit C-119, 1986 Form 10-K, File No. 1-8222)

10.44.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-152, 1986 Form 10-K, File No. 1-8222)

10.44.2 Amendment No. 2 dated November 13, 1986. (Exhibit 10-167, 1987 Form 10-K, File No. 1-8222)

10.44.3 Amendment No. 3 dated January 1, 1987. (Exhibit 10-168, 1987 Form 10-K, File No. 1-8222)

10.45 Copy of Highgate Construction Agreement dated August 1, 1984. (Exhibit C-120, 1984 Form 10-K, File No. 1-8222)

10.45.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-151, 1986 Form 10-K, File No. 1-8222)

10.46 Copy of Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection. (Exhibit C-121, 1984 Form 10-K, File No. 1-8222)

10.46.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-153, 1986 Form 10-K, File No. 1-8222)

10.46.2 Amendment No. 2 dated April 18, 1985. (Exhibit 10-154, 1986 Form 10-K, File No. 1-8222)

10.46.3 Amendment No. 3 dated February 12, 1986. (Exhibit 10-155, 1986 Form 10-K, File No. 1-8222)

10.46.4 Amendment No. 4 dated November 13, 1986. (Exhibit 10-169, 1987 Form 10-K, File No. 1-8222)

10.46.5 Amendment No. 5 and Restatement of Agreement dated January 1, 1987. (Exhibit 10-170, 1987 Form 10-K, File No. 1-8222)

10.47 Copy of the Highgate Transmission Agreement dated August 1, 1984. (Exhibit C-122, 1984 Form 10-K, File No. 1-8222)

10.48 Copy of Preliminary Vermont Support Agreement Re: Quebec Interconnection - Phase II dated September 1, 1984. (Exhibit C-124, 1984 Form 10-K, File No. 1-8222)

10.48.1 First Amendment dated March 1, 1985. (Exhibit C-127, 1985 Form 10-K, File No. 1-8222)

10.49 Vermont Transmission and Interconnection Agreement between New England Power Company and Central Vermont Public Service Corporation and Green Mountain Power Corporation with the consent of Vermont Electric Power Company, Inc., dated May 1, 1985. (Exhibit C-128, 1985 Form 10-K, File No. 1-8222)

10.50 Service Contract Agreement between the Company and the State of Vermont for distribution and sale of energy from St. Lawrence power projects ("NYPA Power") dated as of June 25, 1985. (Exhibit C-130, 1985 Form 10-K, File No. 1-8222)

10.50.1 Lease and Operating Agreement between the Company and the State of Vermont dated as of June 25, 1985. (Exhibit C-131, 1985 Form 10-K, File No. 1-8222)

10.51 System Sales & Exchange Agreement Between Niagara Mohawk Power Corporation and Central Vermont Public Service Corporation dated October 1, 1986. (Exhibit C-133, 1986 Form 10-K, File No. 1-8222)

10.54 Transmission Agreement between Vermont Electric Power Company, Inc. and Central Vermont Public Service Corporation dated January 1, 1986. (Exhibit 10-146, 1986 Form 10-K, File No. 1-8222)

10.55 1985 Four-Party Agreement between Vermont Electric Power Company, Central Vermont Public Service Corporation, Green Mountain Power Corporation and Citizens Utilities dated July 1, 1985. (Exhibit 10-147, 1986 Form 10-K, File No. 1-8222)

10.55.1 Amendment dated February 1, 1987. (Exhibit 10-171, 1987 Form 10-K, File No. 1-8222)

10.56 1985 Option Agreement between Vermont Electric Power Company, Central Vermont Public Service Corporation, Green Mountain Power Corporation and Citizens Utilities dated December 27, 1985. (Exhibit 10-148, 1986 Form 10-K, File No. 1-8222)

10.56.1 Amendment No. 1 dated September 28, 1988. (Exhibit 10-182, 1988 Form 10-K, File No. 1-8222)

10.56.2 Amendment No. 2 dated October 1, 1991. (Exhibit 10.56.2, 1991 Form 10-K, File No. 1-8222)

10.56.3 Amendment No. 3 dated December 31, 1994. (Exhibit 10.56.3, 1994 Form 10-K, File No. 1-8222)

10.56.4 Amendment No. 4 dated December 31, 1996. (Exhibit 10.56.4, 1996 Form 10-K, file No. 1-8222)

10.57 Highgate Transmission Agreement dated August 1, 1984 by and between the owners of the project and the Vermont electric distribution companies. (Exhibit 10-156, 1986 Form 10-K, File No. 1-8222)

10.57.1 Amendment No. 1 dated September 22, 1985. (Exhibit 10-157, 1986 Form 10-K, File No. 1-8222)

10.58 Vermont Support Agency Agreement re: Quebec Interconnection - Phase II between Vermont Electric Power Company, Inc. and participating Vermont electric utilities dated June 1, 1985. (Exhibit 10-158, 1986 Form 10K, File No. 1-8222)

10.58.1 Amendment No. 1 dated June 20, 1986. (Exhibit 10-159, 1986 Form 10-K, File No. 1-8222)

10.59 Indemnity Agreement B-39 dated May 9, 1969 with amendments 1-16 dated April 17, 1970 thru April 16, 1985 between licensees of Millstone Unit No. 3 and the Nuclear Regulatory Commission. (Exhibit 10-161, 1986 Form 10-K, File No. 1-8222)

10.59.1 Amendment No. 17 dated November 25, 1985. (Exhibit 10-162, 1986 Form 10-K, File No. 1-8222)

10.62 Contract for the Sale of 50MW of firm power between Hydro-Quebec and Vermont Joint Owners of Highgate Facilities dated February 23, 1987. (Exhibit 10-173, 1987 Form 10-K, File No. 1-8222)

10.63 Interconnection Agreement between Hydro-Quebec and Vermont Joint Owners of Highgate facilities dated February 23, 1987. (Exhibit 10-174, 1987 Form 10-K, File No. 1-8222)

10.63.1 Amendment dated September 1, 1993 (Exhibit 10.63.1, 1993 Form 10-K, File No. 1-8222)

10.64 Firm Power and Energy Contract by and between Hydro-Quebec and Vermont Joint Owners of Highgate for 500MW dated December 4, 1987. (Exhibit 10-175, 1987 Form 10-K, File No. 1-8222)

10.64.1 Amendment No. 1 dated August 31, 1988. (Exhibit 10-191, 1988 Form 10-K, File No. 1-8222)

10.64.2 Amendment No. 2 dated September 19, 1990. (Exhibit 10-202, 1990 Form 10-K, File No. 1-8222)

10.64.3 Firm Power & Energy Contract dated January 21, 1993 by and between Hydro-Quebec and Central Vermont Public Service Corporation for the sale back of 25 MW of power. (Exhibit 10.64.3, 1992 Form 10-K, File No. 1-8222)

10.64.4 Firm Power & Energy Contract dated January 21, 1993 by and between Hydro-Quebec and Central Vermont Public Service Corporation for the sale back of 50 MW of power. (Exhibit 10.64.4, 1992 Form 10-K, File No. 1-8222)

10.66 Hydro-Quebec Participation Agreement dated April 1, 1988 for 600 MW between Hydro-Quebec and Vermont Joint Owners of Highgate. (Exhibit 10-177, 1988 Form 10-K, File No. 1-8222)

10.66.1 Hydro-Quebec Participation Agreement dated April 1, 1988 as amended and restated by Amendment No. 5 thereto dated October 21, 1993, among Vermont utilities participating in the purchase of electricity under the Firm Power and Energy Contract by and between Hydro-Quebec and Vermont Joint Owners of Highgate. (Exhibit 10.66.1, 1997 Form 10-Q, March 31, 1997, File. No. 1-8222)

10.67 Sale of firm power and energy (54MW) between Hydro-Quebec and Vermont Utilities dated December 29, 1988. (Exhibit 10-183, 1988 Form 10-K, File No. 1-8222)

10.84 Settlement Agreement effective dated June 1, 2001 to which the Company is a party re: Vermont Yankee Nuclear Power Corporation. (Exhibit 10-84, Form 10-Q, June 30, 2001, File No. 1-8222)

10.85 Form of Secondary Purchaser Settlement Agreement dated December 6, 2001, with Acknowledgement and Consent of VELCO, among the Company, Green Mountain Power Corporation and each of: City of Burlington Electric Department; Village of Lyndonville Electric Department; Village of Northfield Electric Department; Village of Orleans Electric Department; Town of Hardwick Electric Department; Town of Stowe Electric Department; and, Washington Electric Cooperative. (Exhibit 10-85, 2001 Form 10-K, File No. 1-8222)

10.86 Purchase and Sale Agreement by and between Public Service Company of New Hampshire and Central Vermont Public Service Corporation/Connecticut Valley Electric Company Inc. dated January 31, 2003. (Exhibit 10-86, Form 10-Q, March 31, 2003, File No. 1-8222)

10.87 Settlement Agreement by and between Connecticut Valley Electric Company Inc. Central Vermont Public Service Corporation The Governor's Office of Energy and Community Services The Staff of the New Hampshire Public Utilities Commission Office of Consumer Advocate The City of Claremont, New Hampshire New Hampshire Legal Assistance dated January 31, 2003. (Exhibit 10-87, Form 10-Q, March 31, 2003, File No. 1-8222)

10.88 Agreement between Central Vermont Public Service Corporation and Local Union No. 300 International Brotherhood of Electrical Workers Effective as of January 1, 2005. (Exhibit 10.88, Current Report on Form 8-K Filed January 5, 2005, File No. 1-8222)

10.89 Financing Agreement among Catamount Sweetwater Holdings LLC; UFJ Bank Limited; Bayerische Landesbank; and The Lenders Parties Hereto dated as of July 12, 2005. (Catamount Sweetwater Holdings LLC is a wholly owned subsidiary of Catamount Energy Corporation. Catamount Energy Corporation is a wholly owned subsidiary of Catamount Resources Corporation. Catamount Resources Corporation is a wholly owned subsidiary of Central Vermont Public Service Corporation. (Exhibit 10.89, Current Report on Form 8-K Filed July 15, 2005, File No. 1-8222)

10.90 Stock Subscription Agreement by and among CEC Wind Acquisition, LLC, Catamount Energy Corporation, Catamount Resources Corporation, and Central Vermont Public Service Corporation, dated October 12, 2005. (Exhibit 10.90, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.1 Form of the Amended and Restated Certificate of Incorporation. (Exhibit 10.90.1, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.2 Stockholders' Agreement among Catamount Energy Corporation and the stockholders parties thereto, dated October 12, 2005. (Exhibit 10.90.2, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.3 Registration Rights Agreement among Catamount Energy Corporation and the stockholders parties thereto, dated October 12, 2005. (Exhibit 10.90.3, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.4 Put Option Purchase and Sale Agreement between Central Vermont Public Service Corporation and CEC Wind Acquisition, LLC, dated October 12, 2005. (Exhibit 10.90.4, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.5 Exercise of Put Option Notice. (Exhibit 10.90.5, Current Report on Form 8-K Filed November 21, 2005, File No. 1-8222)

10.92 Voting Agreement and Irrevocable Proxy between Central Vermont Public Service Corporation and Mr. Jerry Zucker. (Exhibit 10.92, Current Report on Form 8-K Filed March 16, 2006, File No. 1-8222)

10.93 Memorandum of Understanding, dated September 11, 2006, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.93, Current Report on Form 8-K Filed September 11, 2006, File No. 1-8222)

10.93.1 First Amendment to Memorandum of Understanding, dated November 3, 2006, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.93, Current Report on Form 8-K Filed November 6, 2006, File No. 1-8222)

10.94 Operating Agreement of Vermont Transco, LLC effective July 1, 2006. (Exhibit 10.94, 2006 Form 10-K, File No. 1-8222)

10.95 Amended and Restated 1991 Transmission Agreement between Vermont Transco, LLC and (to electric utilities furnishing service within the State of Vermont) effective June 20, 2006. (Exhibit 10.95, 2006 Form 10-K, File No. 1-8222)

10.96 Memorandum of Understanding, dated November 29, 2007, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.96, Current Report on Form 8-K Filed November 30, 2007, File No. 1-8222)

10.97 Credit Agreement dated as of December 28, 2007 between Central Vermont Public Service Corporation, as Borrower and KeyBank National Association, as Lender. (Exhibit 10.97, Current Report of Form 8-K Filed January 4, 2008, File No. 1-8222)

EXECUTIVE COMPENSATION PLANS AND ARRANGEMENTS

A 10.1 Directors' Supplemental Deferred Compensation Plan dated November 4, 1985. (Exhibit 10-188, 1988 Form 10-K, File No. 1-8222)

A 10.1.1 Amendment dated October 2, 1995. (Exhibit 10.72.1, 1995 Form 10-K, File No. 1-8222)

A 10.2 Directors' Supplemental Deferred Compensation Plan dated January 1, 1990 (Exhibit 10.80, 1993 Form 10-K, File No. 1-8222)

A 10.2.1 Amendment dated October 2, 1995. (Exhibit No. 10.80.1, 1995 Form 10-K, File No. 1-8222)

A 10.3 Officers' Supplemental Retirement and Deferred Compensation Plan, Amended and Restated Effective January 1, 2005. (Exhibit A 10.85.1, 2004 Form 10-K, File No. 1-8222)

A 10.4 1997 Stock Option Plan for Key Employees (Exhibit 4.3 to Registration Statement, Registration 333-57001)

A 10.5 Officers' Change of Control Agreements as approved April 3, 2000. (Exhibit A 10.92, Form 10-Q, March 31, 2000, File No. 1-8222)

A 10.6 2000 Stock Option Plan for Key Employees. (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 28, 2000, File No. 1-8222) - (Exhibit A 10.95, September 30, 2006 Form 10-Q, File No. 1-8222)

A 10.7 Deferred Compensation Plan for Officers and Directors of Central Vermont Public Service Corporation, Amended and Restated Effective January 1, 2005. (Exhibit A 10.96.1, 2004 Form 10-K, File No. 1-8222)

A 10.8 2002 Long-Term Incentive Plan. (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 29, 2002, File No. 1-8222) - (Exhibit A 10.95, September 30, 2006 Form 10-Q, File No. 1-8222)

A 10.9 Performance Share Incentive Plan, Effective January 1, 2006. (Exhibit A 10.100.2, 2005 Form 10-K, File No. 1-8222)

* A 10.9.1 Performance Share Incentive Plan, Effective January 1, 2006 and Amended January 1, 2008.

A 10.10 Performance Share Incentive Plan, Effective January 1, 2007. (Exhibit A 10.100.3, 2006 Form 10-K, File No. 1-8222)

* A 10.10.1 Performance Share Incentive Plan, Effective January 1, 2007 and Amended January 1, 2008.

* A 10.11 Performance Share Incentive Plan, Effective January 1, 2008.

A 10.12 Form of Central Vermont Public Service Performance Share Agreement Pursuant to the Performance Share Incentive Plan. (Exhibit A 10.101, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.13 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2002 Long-Term Incentive Plan. (Exhibit A 10.102, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.14 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2000 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.103, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.15 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 1997 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.104, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.16 Form of Indemnity Agreement between Directors and Executive Officers and Central Vermont Public Service Corporation. (Exhibit A 10.105, 2004 Form 10-K, File No. 1-8222)

A 10.17 Change-In-Control Agreement dated as of November 17, 2003 between the Company and Dale A. Rocheleau. (Exhibit A 10.106, 2004 Form 10-K, File No. 1-8222)

* A 10.18 Management Incentive Plan, Effective as of January 1, 2008.

A - Compensation related plan, contract, or arrangement.

12 Statements Regarding Computation of Ratios

* 12.1 Statements Regarding Computation of Ratios

21 Subsidiaries of the Registrant

* 21.1 List of Subsidiaries of Registrant

23 Consent of Independent Registered Public Accounting Firm

* 23.1 Consent of Independent Registered Public Accounting Firm (D&T)

* 23.2 Independent Auditors' Consent (KPMG - VYNPC)

* 23.3 Consent of Independent Registered Public Accounting Firm (KPMG - VELCO)

* 23.4 Consent of Independent Registered Public Accounting Firm (KPMG - VT Transco)

24 Power of Attorney

* 24.1 Power of Attorney executed by Directors and Officers of Company

* 31.1 Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

* 31.2 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

* 32.1 Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* 32.2 Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* 99.1 Financial Statements of Vermont Yankee Nuclear Power Corporation.

* 99.2 Financial Statements of Vermont Electric Power Company, Inc. and Subsidiary

* 99.3 Financial Statements of Vermont Transco LLC.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
Schedule II - Valuation and Qualifying Accounts
For the Years Ended December 31

	Balance at beginning of year	Additions: Charged to cost and expenses	Additions: Charged to other accounts	Deductions	Balance at end of year
2007					
Reserves deducted from assets to which they apply:					
			$127,125 (1)		
			405,882 (2)		
Reserve for uncollectible accounts receivable	$1,706,747	$2,412,498	$533,007	$2,901,183 (4)	$1,751,069
Reserve for uncollectible accounts receivable - affiliates	$47,848				$47,848
				$234,401	
				330,899 (9)	
Accumulated depreciation of non-utility property	$4,047,663	$199,629		$565,300	$3,681,992
Reserves shown separately:					
Environmental Reserve	$2,076,282			$158,608	$1,917,674
2006					
Reserves deducted from assets to which they apply:					
			$106,373 (1)	$1,757,826 (4)	
			762,154 (2)	1,390,104 (7)	
Reserve for uncollectible accounts receivable	$2,614,137	$1,372,013	$868,527	$3,147,930	$1,706,747
Reserve for uncollectible accounts receivable - affiliates	$47,913			$65	$47,848
Accumulated depreciation of non-utility property	$4,063,491	$201,469		$217,297	$4,047,663
Reserves shown separately:					
Injuries and damages reserve (5)	$200,000			$200,000	$-
Environmental Reserve	$5,426,110			$3,349,828 (8)	$2,076,282
2005					
Reserves deducted from assets to which they apply:					
			$118,657(1)		
			479,489 (2)		
			433,169 (3)		
Reserve for uncollectible accounts receivable	$1,948,341	$1,048,860	$1,031,315	$1,414,379 (4)	$2,614,137
Reserve for uncollectible accounts receivable - affiliates	$-	$47,913			$47,913
Accumulated depreciation of non-utility property	$4,877,179	$27,821		$841,509	$4,063,491
Discontinued operations - Catamount	$762,923			$762,923	$-
Reserves shown separately:					
Injuries and damages reserve (5)	$225,580			$25,580	$200,000
Environmental Reserve	$6,064,654			$638,544 (6)	$5,426,110

(1) Amount collected from collection agencies
(2) Collections of accounts previously written off
(3) Reserve against rents
(4) Uncollectible accounts written off
(5) This represents the Company's long-term reserve for injuries & damages needed to meet the Company's liability not covered by insurance. The Company is self-insured up to $200,000; therefore, any activity for the year is charged to expense and recorded to the current liability.
(6) Environmental remediation payments from reserve
(7) Settlement of accounts related to pole attachment tariff resolution
(8) Reduction of reserve based on updated cost estimates for remediation
(9) Reclassified to utility property

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
(Registrant)

By: /s/ Pamela J. Keefe
Pamela J. Keefe
Vice President, Chief Financial Officer, and Treasurer

March 11, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 11, 2008.

Signature	Title
Robert H. Young*	President and Chief Executive Officer, and Director (Principal Executive Officer)
/s/ Pamela J. Keefe (Pamela J. Keefe)	Vice President, Chief Financial Officer, and Treasurer (Principal Financial and Accounting Officer)
Mary Alice McKenzie*	Chair of the Board of Directors
Robert L. Barnett*	Director
Robert G. Clarke*	Director
Bruce M. Lisman*	Director
William R. Sayre*	Director
Janice L. Scites*	Director
William J. Stenger*	Director
Douglas J. Wacek*	Director

By: /s/ Pamela J. Keefe
(Pamela J. Keefe)
Attorney-in-Fact for each of the persons indicated.

* Such signature has been affixed pursuant to a Power of Attorney filed as an exhibit hereto and incorporated herein by reference thereto.