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

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2009

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 ☒

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 ☒

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ 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 ☒

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 ☒

The aggregate market value of voting and non-voting common equity held by non affiliates of the registrant as of June 30, 2009 (2nd quarter) was approximately $174,206,799 (based on the $18.10 per share closing price of the Company's Common Stock, $6 Par Value, as reported on the New York Stock Exchange on June 30, 2009). 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, 2009, 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 26, 2010 there were outstanding 11,729,766 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 4, 2010 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.

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CENTRAL VERMONT PUBLIC SERVICE CORPORATION

Cautionary Statements 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 alternative regulation;
- liquidity risks;
- performance and continued operation of the Vermont Yankee nuclear power plant;
- changes in the cost or availability of capital;
- our ability to replace or renegotiate our long-term power supply contracts;
- effects of and changes in local, national and worldwide economic conditions;
- effects of and changes in weather;
- volatility in wholesale power markets;
- our ability to maintain or improve our current credit ratings;
- the operations of ISO-New England;
- 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;
- performance of other parties in joint projects, including other Vermont utilities and Transco;
- our ability to successfully manage a number of projects involving new and evolving technology;
- 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 ("we", "us", "our" or the "company") is the largest electric utility in Vermont. We engage principally in the purchase, production, transmission, distribution and sale of electricity. We serve approximately 159,000 customers in 163 towns, villages and cities in Vermont. Our Vermont utility operation is our core business. We typically generate most of our revenues through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-New England, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue generated from these sales helps to mitigate our power supply costs.

Our wholly owned subsidiaries include:

- Custom Investment Corporation ("Custom"), 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. On December 30, 2009, Custom transferred the VYNPC shares back to us. We plan to dissolve Custom in 2010.
- 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., formed to finance and construct a hydroelectric facility in Vermont, which became operational September 1, 1984. We have leased and operated it since the in-service date.
- Catamount Resources Corporation ("CRC"), formed to hold our investments in unregulated business opportunities. CRC's wholly owned subsidiary, Eversant Corporation, engages in the sale and rental of electric water heaters in Vermont and New Hampshire through a wholly owned subsidiary, SmartEnergy Water Heating Services, Inc.

- 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. Its remaining assets were nominal.

Our equity ownership interests as of December 31, 2009 are summarized below:

- 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, the plant was sold to Entergy Nuclear Vermont Yankee, LLC ("Entergy-Vermont Yankee"). The sale agreement included a purchased power contract between VYNPC and Entergy-Vermont Yankee. Under the purchased power contract, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates, and in turn, bills the purchased power contract charges from Entergy-Vermont Yankee with certain residual costs of service through a FERC tariff to us and the other Vermont Yankee sponsors. Although we own a majority of the shares of VYNPC, our ability to exercise control is effectively restricted by the purchased power contract, the sponsor agreement among the group of New England utilities that formed VYNPC and the composition of the board of directors under which it operates.
- We own 47.05 percent of the common stock and 48.03 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"). In June 2006, VELCO transferred substantially all of its business operations and assets to Vermont Transco LLC ("Transco"). 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 the rest of New England.
- We own 33.35 percent of the voting equity units of Transco, which was formed by VELCO and its owners, including us, in June 2006. Transco owns and operates the high-voltage transmission system in Vermont. VELCO and its employees manage the operations of Transco under a Management Services Agreement. VELCO owns 11.32 percent of the voting equity units of Transco. Our total direct and indirect (through our VELCO ownership) interest in Transco is 38.68 percent of the voting equity units.
- 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"). These plants have been decommissioned.

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

(b) Financial Information about Industry Segments We have two principal operating segments, consisting of the principal regulated utility business and the aggregate of the other non-utility companies. See Part II, Item 8, Note 18 - Segment Reporting for financial information by segment.

(c) Narrative Description of Business 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 our geographic location and the nature of our customer base, weather and economic conditions 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 a decrease of about 3 percent in 2009, due primarily to the poor economy, to increases of over 2 percent in other years.

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 5 percent of our annual retail electric revenues for 2009, and about 6 percent in 2008 and 2007. 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. Operating revenues as of December 31 consisted of the following:

	Revenues			**Energy (mWh) Sales**		
	2009	2008	2007	**2009**	2008	2007
Retail Sales:						
Residential	**41%**	40%	41%	**33%**	33%	33%
Commercial	**30%**	32%	33%	**27%**	29%	29%
Industrial and other	**10%**	11%	11%	**12%**	13%	14%
Resale Sales	**16%**	14%	12%	**28%**	25%	24%
Other operating revenue	**3%**	3%	3%	**0%**	0%	0%

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"). 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. See Part II, Item 8, Note 7 - Retail Rates and Regulatory Accounting.

Wholesale Rates: We provide wholesale transmission service to 10 network customers and five 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 maintain an OASIS site for transmission on the ISO-New England web page.

Sources and Availability of Power Supply Our power supply portfolio includes sources used to serve our retail electric load requirements. Our current power forecast shows energy purchase and production amounts in excess of load obligations through 2011. For the year ended December 31, 2009 energy generation and purchased power required to serve retail customers totaled 2,316,000 mWh. The maximum one-hour integrated demand during that period was 407.4 MW and occurred on December 29, 2009. For 2008, our energy generation and purchased power required to serve retail customers totaled 2,407,000 mWh. The maximum one-hour integrated demand was 414.4 MW and occurred on January 3, 2008. The sources of energy and capacity available to us for the year ended December 31, 2009 are as follows:

	Net Effective Capability 12 Month Average MW	Generated and Purchased mWh	Percent
Wholly Owned Plants:			
Hydro	39.9	216,777	6.8
Diesel and Gas Turbine	21.1	196	0.0
Jointly Owned Plants:			
Millstone #3	21.4	180,266	5.7
Wyman #4	10.8	3,508	0.1
McNeil	10.7	44,482	1.4
Long-Term Purchases:			
VYNPC	179.5	1,551,925	48.8
Hydro-Quebec	143.2	919,764	28.9
Independent power producers	36.7	202,483	6.4
Other Purchases:			
System and other purchases	0.4	3,846	0.1
NEPOOL (ISO-New England)		55,191	1.8
Total	463.7	3,178,438	100.0

Wholly Owned Plants: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of 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. The diesel plant has been deactivated since 2007 but its capacity is included in the above totals.

Jointly Owned Plants: We have joint-ownership interests in three generating facilities and one transmission facility. As shown in the sources and availability of power supply table above, we receive our share of output and capacity from the three generating facilities. The Highgate Converter 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. Additional information about these facilities is shown in the table below.

	Fuel Type	Ownership	Date In Service	MW Entitlement
Wyman #4	Oil	1.78%	1978	10.8
Joseph C. McNeil	Various	20.00%	1984	10.8
Millstone Unit #3	Nuclear	1.73%	1986	21.4
Highgate Transmission Facility		47.52%	1985	N/A

VYNPC: We purchase our entitlement share of Vermont Yankee plant output from VYNPC under a long-term power contract between VYNPC and Entergy-Vermont Yankee. The contract extends through the plant's current license life, which expires in March 2012. Prices per megawatt-hour under the contract range from $43 in 2010 to $45 in 2012, and the contract 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.

Entergy-Vermont Yankee 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 plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. The next refueling outage is scheduled for the spring of 2010. We typically enter into forward purchase contracts for replacement power during scheduled outages.

We have a forced outage insurance policy to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The current policy covers March 22, 2009 through March 21, 2010. In October 2009, we purchased coverage for the period March 22, 2010 through March 21, 2011. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters.

Entergy-Vermont Yankee has submitted a renewal application with the NRC and an application for a Certificate of Public Good ("CPG") with the PSB for a 20-year extension of the Vermont Yankee plant operating license. Entergy-Vermont Yankee also needs approval from the PSB and Vermont Legislature to continue to operate beyond 2012. Significant hurdles may prevent its relicensing. Potential operating, transparency and communication issues related to the plant and its operations have raised serious concerns among regulators and members of the Vermont Legislature, including some who have called for its temporary or permanent shutdown. An intervenor in the CPG case has requested that the PSB order a shutdown of the Vermont Yankee plant pending resolution of current tritium leaks at the site. The PSB has opened a new docket to consider that request. We are unable to predict the outcome of this matter.

On February 24, 2010, in a non-binding vote, the Vermont Senate voted against allowing the PSB to consider granting the Vermont Yankee plant another 20-year operating license after 2012. A new Vermont legislature will be elected in the fall of 2010 and could vote differently. We are unable to predict the outcome of this matter.

At this time, Entergy-Vermont Yankee is attempting to overcome these concerns, but we have not held any formal negotiations on a new contract since these issues arose in January. We rejected Entergy-Vermont Yankee's current proposal, but both parties are prepared to resume negotiations for a purchased power contract when the issues that have emerged are resolved. We cannot predict the outcome at this time. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Other Business Risks - Power Supply Risks.

Hydro-Quebec: We purchase 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. Related contracts were subsequently negotiated between us and 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 November 1, 2007 the annual load factor was reduced from 80 percent to 75 percent, and it will remain at 75 percent until the contract ends, unless the contract is changed or there is a reduction due to adverse hydraulic conditions.

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 use water and biomass as fuel. Most of the power is allocated by a state-appointed purchasing agent that assigns power to all Vermont utilities under PSB rules.

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 power supply 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, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters and Part II, Item 8, Note 17 - 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 Title 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. Such sales have not been made in our service area since 1993.

In addition, Chapter 79 of Title 30 of the V.S.A. authorizes municipalities to acquire the electric distribution facilities located within their boundaries. Over the years a handful of municipalities have investigated the possibility of acquiring our distribution facilities. However, no municipality served by us has successfully established a municipal electric distribution system. We cannot predict whether efforts to municipalize portions of our service territory will occur in the future or be successful, and if so, what the impact would be on our financial condition.

Regulation We are subject to regulation by the PSB, other state commissions, FERC and the NRC as described below.

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 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 limited jurisdiction based on our interest in Millstone Unit #3.

Federal Power Act: Certain phases of our business and that of VELCO and Transco, including certain rates, are subject to regulation by 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. On February 25, 2009, we received a federal license to continue to operate our Carver Falls hydroelectric facility and on February 26, 2009, we received a federal license to continue to operate our Silver Lake hydroelectric facility. These projects represent about 4.1 MW, or 9 percent of our hydroelectric nameplate capacity.

Federal Energy Policy Act of 2005: The Federal Energy Policy Act of 2005 ("EPACT") 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 EPACT. We have received a blanket exemption from the FERC to acquire securities of Transco, which previously required FERC approval.

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.

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 with respect to 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. See Part II, Item 8, Note 17 - Commitments and Contingencies.

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.

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 cost effectiveness, energy efficiency, service, convenience, cleanliness, automatic delivery and safety.

In the large commercial and industrial sectors many of these same factors are expected to influence demand. Additionally, cogeneration and self-generation can be 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 network electricity in those segments can be: cost effectiveness and 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 distributed generation, net metering and cogeneration could provide benefits to us in the constrained areas of our system.

In the near-term, increasing appliance efficiency standards, the slowly recovering economy and Vermont's energy efficiency programs will result in very slow or negative demand growth. In the longer term, we expect that the emergence of new hyper-efficient space and water heating technologies, the use of electricity as a transportation energy source, Smart Grid pricing programs and carbon gas regulation may result in somewhat higher, but most likely very slow, growth in power demand.

Another possible competitive threat we face is the potential for customers to acquire our assets through a process known as municipalization. This is described above under the caption Franchise.

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 and longer hours of darkness contribute to higher sales in the winter, while air conditioning generates higher sales in the summer. Consumption is lowest in the spring and fall, when there is decreased heating or cooling load.

Capital Expenditures Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system. Capital expenditures in 2009 amounted to $31.4 million. Capital expenditures for the next five years are expected to range from $37 million to $53 million annually, including an estimated total of more than $60 million for CVPS SmartPower™ over the 5-year period. On October 27, 2009, the U.S. Department of Energy ("DOE") announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer enhancements and grid automation. As a participant on Vermont's smart grid stimulus application, we expect to receive a grant of over $31 million. This award will fund a portion of the $60 million SmartPower project discussed above and is reflected in the five-year capital expenditure estimates above. We are now negotiating with the DOE and other Vermont utilities to finalize funding and requirements. The 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.

Competitive advantages may also develop for us as we begin to implement CVPS SmartPower™ within our service territory. A smart grid delivers electricity from suppliers to consumers using digital technology to save energy and cost. Although there are specific and proven smart grid technologies in use, *smart grid* is an aggregate term for a set of related technologies rather than a name for a specific technology with a generally agreed-upon specification. Some of the expected benefits of such a modernized electricity network include more efficient use of the grid, reducing consumer power consumption during peak hours, enabling grid connection of distributed generation, reducing the duration of outages, enhanced system management, reduced operating costs and incorporating grid energy storage for distributed generation load balancing.

Number of Employees At December 31, 2009, we had 534 employees. Of these employees, 213 were represented by Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers ("IBEW"). On December 31, 2008, we agreed to a new five-year contract with our employees represented by the union, which expires on December 31, 2013. Over time, our number of employees has been reduced in anticipation of CVPS SmartPower™ operational efficiencies and for other reasons.

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, 62	Chair of the board of directors, President and chief executive officer	1987
Pamela J. Keefe, 44	Senior vice president, chief financial officer, and treasurer	2006
William J. Deehan, 57	Vice president - power planning and regulatory affairs	1991
Joan F. Gamble, 52	Vice president - strategic change and business services	1998
Brian P. Keefe, 52	Vice president - government and public affairs	2006
Joseph M. Kraus, 54	Senior vice president - operations, engineering and customer service	1987
Dale A. Rocheleau, 51	Senior vice president, general counsel and corporate secretary	2003

Mr. Young joined the Company in 1987, was elected to his present position in 1995, and was appointed chair of the board in February 2010. Mr. Young also serves as president, CEO, and chair of the our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; Custom; CRC; Eversant Corporation; and SmartEnergy Water Heating Services, Inc. He serves as chair of the board of directors of our affiliate, VYNPC. He is also a director of our affiliates: VELCO and Vermont Electric Transmission Company, Inc. Mr. Young is a director of the Edison Electric Institute, Inc., Vermont Business Roundtable, Associated Industries of Vermont, and the Weston Playhouse Theatre Company. He is a member of the advisory board of The Chittenden Trust Company, a division of People's United Bank.

Ms. Keefe joined the company in June 2006. Prior to being elected to her present position she served as vice president, chief financial officer, and treasurer from June 2006 to May 2009. 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 a 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. Additionally, Ms. Keefe serves as a member of the Rutland Regional Medical Center Investment Committee.

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. He serves as a director of the Joseph C. McNeil Generating Station, the Vermont Electric Power Producers, Inc., and the Rutland County Boys and Girls Club. Additionally, Mr. Deehan is a member of the International Association of Energy Economists and the Organizing Committee of the Rutgers University Advanced Regulatory Economics Workshop.

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. She is also on the board of the Vermont Achievement Center, Rutland Regional Medical Center, Rutland Regional Health Service, and Vermont Public Television. She is a member of the Vermont Supreme Court's Commission on Judicial Operation.

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. He is on the board of the Vermont Chamber of Commerce and is a member of the Vermont Council on the Future of Vermont.

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 a director of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and SmartEnergy Water Heating Services, Inc. Additionally, Mr. Kraus serves as a director and president of The Mentor Connector (a community-based, non-profit organization that matches volunteer mentors with children in need) and is a member of the Governor's Homeland Security Advisory Council.

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 a director and attorney at law from 1992 to 2003 with Downs Rachlin Martin, PLLC. Mr. Rocheleau serves as a 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. He is also a trustee of the University of Vermont and State Agricultural College Board of Trustees. Additionally, he serves as a director of the Hartford Land Company, the Greater Burlington Industrial Corporation, Cynosure, Inc., and the Rutland Economic Development Corporation. Mr. Rocheleau is also a member of the Governor's Council of Environmental Advisors.

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 to implement energy efficiency programs throughout 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 Vermont's 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 owned and operated by Transco. The PSB appointed three members of the public, along with representatives of the state's utilities, including us, to the newly created Vermont System Planning Committee to oversee that process. In 2006, the Vermont Legislature 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.

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 additional 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, Management's Discussion and Analysis of Financial Condition and Results of Operations, Recent Energy Policy Initiatives.

(d) Financial Information about Geographic Areas Neither we nor our subsidiaries have any foreign operations or export sales. The regulated utility business engages in the purchase, production, transmission, distribution and sale of electricity in Vermont as well as the transmission of energy in New Hampshire and the generation of energy in New York, Maine and Connecticut. SmartEnergy Water Heating Services, Inc. engages in the sale and rental of electric water heaters in Vermont and New Hampshire.

(e) Available Information
We make available free of charge through our Internet Web site, *www.cvps.com,* our 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 Web site 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 Web site. Access to these documents is available from the main page of our Internet Web site 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 Web site, *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 1-800-732-0330.

Item 1A. Risk Factors
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. Also see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Other Business Risks and Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

We are subject to substantial utility-related regulation on the federal, state and local levels, and changes in regulatory or legislative policy could jeopardize our full recovery of costs. At the federal level, the FERC regulates our transmission rates, affiliate transactions, the acquisition by us of securities of regulated entities and certain other aspects of our business. The PSB regulates the rates, terms and conditions of service, various business practices and transactions, financings, transactions between us and our affiliates, and the siting of our transmission and generation facilities and our ability to make repairs to such facilities. Our allowed rates of return, rate structures, operation and construction of facilities, rates of depreciation and amortization, and recovery of costs (including decommissioning costs and exogenous costs such as storm response-related expenses), are all determined within the regulatory process. The timing and adequacy of regulatory relief directly affect our results of operations and cash flows. 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 deny the recovery of costs incurred for the operation, maintenance, and construction of our regulated assets, as well as reduce our return on investment. Furthermore, compliance with regulatory and legislative requirements could result in substantial costs in our operations that may not be recovered. Also see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Retail Rates and Alternative Regulation, for additional information about our Alternative Regulation Plan that became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension.

We are subject to the effects of changes in Vermont state government resulting from elections of public officials, including the governor and appointees of the PSB. A change in public officials could have implications on our regulatory relationships and future rate settlements. New officials could have different views on various regulatory issues.

Unexpected ice, wind and snow storms or extraordinarily severe weather can dramatically increase costs, with a significant lapse of time before we recover these costs through our rates. The demand for our services and our ability to provide them without material unplanned expenses are directly affected by weather conditions. We serve a largely rural, rugged service territory with dense forestation that is subject to extreme weather conditions. Storm activity has been significant in recent years, with the two most expensive storms in our history occurring in 2007 and 2008. Our results of operations can be affected by changes in weather. Severe weather conditions such as ice and snow storms, high winds and 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. Weather conditions also directly influence the demand for electricity.

We are currently recovering storm response-related costs from the 2008 major storm under our alternative regulation plan, but are unable to predict whether future major storm costs will qualify as an exogenous factor or if we will receive regulatory approval for full recovery of costs.

We are subject to extensive federal, state and local environmental regulation that could have a material adverse effect on our financial position, results of operations or cash flows. We are subject to federal, state and local environmental regulations that monitor, among other things, emission allowances, pollution controls, maintenance, site remediation, equipment upgrades and management of hazardous waste. Various governmental agencies require us to obtain environmental licenses, permits, inspections and approvals. Compliance with environmental laws and requirements can impose significant costs, reduce cash flows and result in plant shutdowns or reduced plant output.

Any failure by us to comply with environmental laws and regulations, even if due to factors beyond our control or reinterpretations of existing requirements, could also increase costs. Existing environmental laws and regulations may be revised or new laws and regulations seeking to protect the environment may be adopted or become applicable to us. The cost impact of any such legislation would be dependent upon the specific requirements adopted and cannot be determined at this time. Also, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Recent Energy Policy Initiatives.

Greenhouse gas emission legislation or regulations, if enacted, could significantly increase the wholesale cost of power, capital expenditures or operating costs. Global climate change issues have received an increased focus on the federal and state government levels which could potentially lead to additional rules and regulations that impact how we operate our business, including power plants we own and general utility operations. The ultimate impact on our business would be dependent upon the specific rules and regulations adopted and we cannot predict the effects of any such legislation at this time. We anticipate that compliance with greenhouse gas emission limitations for all suppliers may entail replacement of existing equipment, installation of additional pollution control equipment, purchase of emissions allowances, curtailment of certain operations or other actions. Also, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Recent Energy Policy Initiatives.

Our business is affected by local, national and worldwide economic conditions, and due to current market volatility, we have a number of cash flow risks. If the current economic crisis intensifies or is sustained for a protracted period of time, potential disruptions in the capital and credit markets may adversely affect our business. There could be adverse effects on: the availability and cost of short-term funds for liquidity requirements; the availability of financially stable counterparties for the forward purchase and forward sale of power; the availability and cost of long-term capital to fund our asset management plan and future investments in Transco; additional funding requirements for our pension trust due to declines in asset values to fund pension liabilities; and the performance of the assets in our Rabbi Trust and decommissioning trust funds.

Longer-term disruptions in the capital markets as a result of economic uncertainty, changes in regulation, reduced financing alternatives or failures of financial institutions could adversely affect our access to the funds needed to operate our business. Such prolonged disruptions could require us to take measures to conserve cash until the markets stabilize. In addition, 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.

The global economic crisis resulted in a significant decline in lending activity, which has recently begun to abate. We have a $40 million unsecured revolving credit facility and a $15 million unsecured revolving credit facility with different banks. Our access to funds under the revolving credit facilities is dependent on the ability of the counterparty banks to meet the funding commitments. The counterparty banks may not be able to meet the funding commitments if they experience shortages of capital and liquidity or excessive volumes of borrowing requests from other borrowers within a short period.

We are currently reviewing options to issue debt and equity to support working capital requirements resulting from investments in our distribution and transmission system. On November 6, 2009, we filed a Registration Statement on Form S-3 with the SEC requesting the ability to offer, from time to time and in one or more offerings, up to $55 million of our common stock. On December 4, 2009, the SEC declared the Registration Statement to be effective. On January 15, 2010, we filed a Prospectus Supplement with the SEC noting that we entered into an Equity Distribution agreement allowing us to issue up to $45 million of shares under an "at-the-market" offering program. As of December 31, 2009, no shares have been issued under this arrangement.

We are subject to investment price risk due to equity market fluctuations and interest rate changes, which could result in higher contributions and more cash outflows. Interest rate changes and volatility in the equity markets could impact the values of the debt and equity securities in our pension and postretirement medical trust funds and the valuation of pension and other benefit liabilities, affecting pension and other benefit expenses, contributions to the external trust funds and our ability to meet future pension and postretirement benefit obligations. Interest rate changes and volatility in the equity markets could also impact the value of the debt securities in our nuclear decommissioning trust.

We have risks related to our power supply and wholesale power market prices and we could be exposed to high wholesale power prices that could be material. Our material power supply contracts are with Hydro-Quebec and VYNPC. The power supply contracts with Vermont Yankee and Hydro-Quebec comprise the majority of our total annual energy purchases. Combined, these contracts amount to approximately 90 percent of our total energy purchases. If one or both of these sources become unavailable for a period of time, we could be exposed to high wholesale power prices and that amount could be material. Additionally, this could significantly impact our 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. Most incremental replacement power costs would be recovered through the power cost adjustment mechanism in our alternative regulation plan or we could seek emergency rate relief from our regulators if this were to occur. Such relief may or may not be provided and if it is provided we cannot predict its timing or adequacy.

Our contract for power purchases from Vermont Yankee ends in March 2012, but there is a risk that the plant could be shut down earlier than expected if Entergy-Vermont Yankee, the plant's owner, determines that it is not economical to continue operating the plant or public health issues arise. The plant owners are currently trying to determine the source of a leak of tritium-infused water at the plant, which raised the concerns detailed above. We cannot predict the outcome of this matter or how it might affect us.

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, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.5 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 such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results, if the costs are recovered in retail rates in a timely fashion.

Deliveries under the contract with Hydro-Quebec end in 2016, but the level of deliveries will begin to decrease after 2012. Hydro-Quebec is in a building phase and interested in a new contract. We recently signed a memorandum of agreement, a precursor to a final contract for ongoing Hydro-Quebec supplies. There is a risk that other sources available to fill out our portfolio may not be as reliable, and the price of such replacement power could be significantly higher than what we have in place today.

Extreme weather conditions, breakdowns, war, acts of terrorism or other occurrences could lead to the loss of use or destruction of our facilities or the facilities of third parties that are used in providing our services, or with which our electric facilities are interconnected, and could greatly reduce cash flows and increase our costs of repairs and/or replacement of assets. Our ability to provide energy delivery and related services depends on our operations and facilities and those of third parties, including ISO-New England and electric generators from which we purchase electricity. While we carry property insurance to protect certain assets and general regulatory precedent may provide for the recovery of losses for such incidents, our losses may not be fully recoverable through insurance or customer rates.

We could recognize financial losses as a result of volatility in the market values of derivative contracts. We use derivative instruments, such as forward contracts, to manage our commodity risk. We also bear the risk of a counterparty failing to perform. While we employ prudent credit policies and obtain collateral where appropriate, counterparty credit exposure cannot be eliminated, particularly in volatile energy markets.

Gains or losses on derivative contracts are marked to market, but we have received approval for regulatory accounting treatment of these mark-to-market adjustments, so there is no impact on our income statement.

Adoption of new accounting pronouncements and application of accounting guidance for regulated operations can impact our financial results. The adoption of new accounting standards and changes to current accounting policies or interpretations of such standards may materially affect our financial position, results of operations or cash flows. Accounting policies also include industry-specific accounting standards applicable to rate-regulated utilities. If we determine that we no longer meet the criteria to account for regulated operations, the accounting impact would be a charge to operations of $11.8 million on a pre-tax basis as of December 31, 2009, assuming no stranded cost recovery would be allowed through a rate mechanism. We would also be required to record pension and postretirement costs of $31.3 million on a pre-tax basis to Accumulated Other Comprehensive Loss and $0.7 million to Retained Earnings as a reduction in stockholders' equity and would be required to determine any potential impairment to the carrying costs of deregulated plant. The financial statement impact resulting from the discontinuance of accounting for regulated operations might also trigger certain defaults under our current financial covenants.

The effect of the adverse impacts from these risk factors on our utility earnings could be mitigated by the earnings sharing adjustment mechanism in the alternative regulation plan effective January 1, 2009.

Anti-takeover provisions of Vermont law, our articles of association and our bylaws may prevent or delay an acquisition of us that stockholders may consider favorable or attempts to replace or remove our management that could be beneficial to our stockholders. Our articles of association and bylaws contain provisions that could make it more difficult for a third party to acquire us without the consent of our board of directors. They provide for our board of directors to be divided into three classes serving staggered terms of three years and permit removal of directors only for cause by the holders of not less than 80 percent of the shares entitled to vote (except where our Senior Preferred Stock has a right to participate in voting after certain arrearages in payments of dividends). Additionally, they require advance notice of stockholder proposals and stockholder nominations to the board of directors. In addition, they impose restrictions on the persons who may call special stockholder meetings. In addition, Vermont law allows directors to consider the interests of constituencies other than stockholders in determining appropriate board action on a recommendation of a business combination to stockholders. The approval of a U.S. government regulator or the PSB will also be required of certain types of business combination transactions. These provisions may delay or prevent a change of control of our company even if this change of control would benefit our stockholders.

We have other business risks related to liquidity. An extended unplanned Vermont Yankee plant outage or similar event could have a significant effect on 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.

Any disruption could require us to take measures to conserve cash until the capital markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures and reducing dividend payments or other discretionary uses of cash.

Our credit facilities 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. We raised $20.9 million, net of issuance costs, in a secondary offering of our common stock in November 2008. The proceeds were used for general corporate purposes including investments in our core infrastructure to maintain system reliability. If we are ever unable to secure needed funding, we would review our corporate goals in response to the 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 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, as a result of high power market prices.

Continued turbulence in the capital markets could limit or delay our ability to obtain additional outside capital on reasonable terms, and could negatively affect our ability to remarket and keep outstanding $10.8 million of our revenue bonds with monthly interest rate resets.

A related liquidity risk is our growing reliance on cash distributions from one of our affiliates. Transco's ability to pay distributions is subject to its financial condition and financial covenants in the various loan documents to which it is a party. Although it is a regulated business, Transco may not always have the resources needed to pay distributions with respect to the ownership units in the same manner as VELCO paid in the past.

Likewise, our business follows the economic cycles of the customers we serve. The economic downturn, subsequent recession and increased cost of energy supply have and could continue to 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. However, the effect of unanticipated reduced consumer demand on our revenue will be offset to a large degree by the power cost and earnings sharing adjustment mechanism in the alternative regulation plan that became effective January 1, 2009. Anticipated consumer demand is reflected in base rates set annually under the plan.

Economic conditions in our service territory also impact our collections of accounts receivable and financial results.

An inability to access capital markets at attractive rates could materially increase our expenses. 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 dependent on our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs could increase materially, our financial condition could be harmed and future results of operations could be adversely affected.

Our current credit rating is subject to change and ratings below investment grade could increase our capital costs and collateral requirements. In December 2009, Moody's Investors Service issued us a corporate credit rating of Baa3, which is investment grade. Subsequently, Standard & Poor's Ratings Services withdrew, at our request, its rating of us which had been BB+ (below investment grade) since June 2005. Restoration of our credit rating to investment grade was a key goal for us during that time. Attaining an investment-grade rating benefits our customers and shareholders by giving us access to lower-cost capital, more power purchase and sale counterparties, and higher collateral thresholds. Looking ahead, as long-term power contracts with Hydro-Quebec and Vermont Yankee begin to expire two years from now, these ratings become even more important.

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. 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. Also, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, Pension and Postretirement Medical Benefits.

We have risks related to the cost and implementation of new technology projects. The CVPS SmartPower ™ ("SmartPower") plan involves the deployment of technologies that may change our business in fundamental ways. We believe these changes will be in the best interest of the company and our customers. However, the full extent of these changes is not yet known or knowable, and we cannot say with certainty that the deployment of these technologies will not present some risks to the company and its operations. As our industry deploys these technologies and their impacts become more understood, we will be able to more precisely estimate the risks, if any, of these technologies on our business.

We are working with the DPS, to reach an agreement on the recovery of costs associated with the plan, and we will seek PSB approval of the agreement. Extensions of the regulatory review process will impact the SmartPower project schedule.

SmartPower is highly dependent on other capital projects. We are working with various parties to build a communications infrastructure that will support an advanced meter infrastructure. VELCO, our transmission affiliate, is in the process of developing its related project plans and milestones for its capital projects. If the milestones of VELCO's projects are out of phase with our SmartPower telecommunications requirements, temporary solutions could add cost to the SmartPower project.

We have risks related to technology interruptions and changes. Our daily operations are heavily dependent on technology and computing systems. While our technological infrastructure is highly reliable, and extended outages and failures are not anticipated, extended outages could adversely impact many aspects of our business. Changes in technology and/or an accelerated rate of change in technology could also have an adverse impact on our business.

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.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

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 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 our First Mortgage Indenture.

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 these properties is set forth under Part I, Item 1, Business, Sources and Availability of Power Supply and is incorporated herein by reference.

At December 31, 2009, our electric transmission and distribution systems consisted of approximately 617 miles of overhead transmission lines, 8,470 miles of overhead distribution lines and 466 miles of underground distribution lines. All are located in Vermont except for approximately 23 miles in New Hampshire and 2 miles in New York.

Transco's properties consist of approximately 621 miles of high-voltage overhead and underground transmission lines and associated substations. The lines connect on the west with the lines of National Grid New York at the Vermont-New York border near Whitehall, N.Y. and Bennington, Vt., and with the submarine cable of New York Power Authority near Plattsburgh, N.Y.; on the south and east with the lines of National Grid New England, Public Service Company of New Hampshire and Northeast Utilities; on the south with the facilities of Vermont Yankee and with National Grid New England near Adams, Mass.; and on the northern border of Vermont with the lines of Hydro-Quebec near Derby, Vt. 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 approximately 52 miles of high-voltage DC transmission lines connecting with the transmission line of Hydro-Quebec at the Quebec-Vermont border in the Town of Norton, Vt. 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. Removed and Reserved

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	
2009	High	Low
First Quarter	**$26.32**	**$16.81**
Second Quarter	**$18.62**	**$15.78**
Third Quarter	**$20.95**	**$17.15**
Fourth Quarter	**$21.10**	**$18.66**
2008		
First Quarter	$32.43	$22.40
Second Quarter	$25.13	$18.74
Third Quarter	$25.84	$18.17
Fourth Quarter	$24.37	$15.16

(b) As of December 31, 2009, there were 5,949 holders of our Common Stock, $6 par value.

(c) Common Stock dividends have been declared quarterly and cash dividends of $0.23 per share were paid for all quarters of 2009 and 2008.

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, 2009, the Common Stock Equity of our unconsolidated company was 52.4 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, 2009, $75.7 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

(in thousands, except per share amounts)

	2009	2008	2007	2006	2005
Income Statement					
Operating revenues	**$342,098**	$342,162	$329,107	$325,738	$311,359
Income from continuing operations (a)	**$20,749**	$16,385	$15,804	$18,101	$1,410
Income from discontinued operations (b)	**0**	0	0	251	4,936
Net income	**$20,749**	$16,385	$15,804	$18,352	$6,346
Per Common Share Data					
Basic earnings from continuing operations	**$1.75**	$1.53	$1.52	$1.65	$0.09
Basic earnings from discontinued operations	**0.00**	0.00	0.00	0.02	0.40
Basic earnings per share	**$1.75**	$1.53	$1.52	$1.67	$0.49
Diluted earnings from continuing operations	**$1.74**	$1.52	$1.49	$1.64	$0.08
Diluted earnings from discontinued operations	**0.00**	0.00	0.00	0.02	0.40
Diluted earnings per share	**$1.74**	$1.52	$1.49	$1.66	$0.48
Cash dividends declared per share of common stock	**$0.92**	$0.92	$0.92	$0.69	$1.15
Balance Sheet					
Long-term debt (c) (d)	**$201,611**	$167,500	$112,950	$115,950	$115,950
Capital lease obligations (d)	**$4,313**	$5,173	$5,889	$6,612	$6,153
Redeemable preferred stock (d)	**$0**	$1,000	$2,000	$3,000	$4,000
Total capitalization (d)	**$445,401**	$401,206	$317,700	$312,968	$351,527
Total assets (e)	**$632,152**	$626,126	$540,314	$500,938	$551,433

(a) For 2005, includes a $21.8 million pre-tax charge to earnings ($11.2 million after-tax) related to a 2005 Rate Order.
(b) For 2006 and 2005, includes Catamount, which was sold in the fourth quarter of 2005.
(c) For 2009 and 2008, includes $60 million of newly issued 6.83%, Series UU first mortgage bonds, due in 2028.
(d) Amounts exclude current portions.
(e) We invested $20.8 million in Transco in 2009, $3.1 million in 2008, $53 million in 2007 and $23.3 million in 2006.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

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. The discussion below also includes non-GAAP measures referencing earnings per diluted share for variances described below in Results of Operations. We use this measure to provide additional information and believe that this measurement is useful to investors to evaluate the actual performance and contribution of our business activities. This non-GAAP measure should not be considered as an alternative to our consolidated fully diluted earnings per share determined in accordance with GAAP as an indicator of our operating performance. Also, please refer to our "Cautionary Statement Regarding Forward-Looking Information" section preceding Part I, Item 1, Business of this Form 10-K.

COMPANY OVERVIEW

We are regulated by the Vermont Public Service Board ("PSB"), the Federal Energy Regulatory Commission ("FERC") and the Connecticut Department of Public Utility Control with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. 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. As discussed under the heading Retail Rates and Alternative Regulation below, the PSB approved, with modifications, the alternative regulation plan that we proposed in August 2007, with modifications. The implementation of this plan on January 1, 2009, has provided timelier rate adjustments to reflect changes in power, operating and maintenance costs, which better serve the interests of customers and shareholders.

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 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 a decrease of about 3 percent in 2009, primarily due to the poor economy, to increases of over 2 percent in other years. We currently have sufficient power resources to meet or exceed our forecasted load requirements through March 2012.

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.

EXECUTIVE SUMMARY

Our consolidated 2009 earnings were $20.7 million, or $1.74 per diluted share of common stock. This compares to consolidated 2008 earnings of $16.4 million, or $1.52 per diluted share of common stock, and consolidated 2007 earnings of $15.8 million, or $1.49 per diluted share of common stock. The primary drivers of earnings variances for the three years are described in Results of Operations below.

A December 2008 ice storm did unprecedented damage to significant portions of our electrical system in rugged, rural sections of southern and eastern Vermont. The restoration effort resulted in our most expensive storm recovery with costs of more than $5 million, exceeding the repair costs we incurred as a result of the so-called Nor'icane of 2007, previously the most expensive storm in our history with incremental storm restoration costs totaling $3.5 million. Our rates include a five-year average of storm restoration costs, but given the magnitude of the ice storm, that average will not fully recover our current costs. We filed a motion with the PSB to allow us to defer the portion of the ice storm recovery costs not reflected in rates, and to recover those costs over a one-year period beginning July 1, 2009. On February 12, 2009, the PSB approved our request. The amount of the deferral, based on actual costs, was $3.2 million.

While these storms presented enormous challenges, employees' responses won the company accolades within Vermont and nationally. The Vermont Legislature passed resolutions praising the company's efforts in both instances. Employees' efforts also earned the 2007 and 2008 Edison Electric Institute's Emergency Recovery Awards, the industry's highest honor for storm recovery and response.

The equity markets affect the value of our employee benefit and nuclear decommissioning trust funds and the cash surrender value of variable life insurance policies included in our Rabbi Trust. The fair value of our pension and postretirement trust fund investments increased $23.8 million during 2009 as the equity markets began to recover from losses sustained in 2008. The fair value of our pension and postretirement trust fund investments decreased $16.3 million during 2008, principally due to the decline in equity markets. In 2009, the value of our Millstone Unit #3 nuclear decommissioning trust fund increased by $0.9 million, and the cash surrender value of certain variable life insurance policies increased by $1.1 million, as the equity markets began to recover from losses sustained in 2008. In 2008, the value of our Millstone Unit #3 nuclear decommissioning trust fund decreased by $1.4 million, and the cash surrender value of certain variable life insurance policies decreased by $2 million, principally due to the downturn of the equity markets. See Results of Operations, Liquidity and Capital Resources, Pension and Postretirement Medical Plan below for additional information.

During 2009, we made progress on several key strategic financial initiatives including:

- Our corporate credit rating was returned to investment grade. In December 2009, Moody's Investors Service issued us a corporate credit rating of Baa3, which is investment grade. Subsequently, Standard & Poor's Ratings Services withdrew, at our request, its rating of us which had been BB+ since May 2005.
- In December 2009 we made a $20.8 million investment in Transco. This increased our equity investment in Transco to $114.7 million at December 31, 2009. See Liquidity, Capital Resources and Commitments.
- In December 2009, we obtained a 364-day, $15 million revolving credit facility with a bank in addition to an existing $40 million revolving credit facility with a different bank.

Other financial initiatives that we continue to focus on include maintaining sufficient liquidity to support ongoing operations, the dividend on our common stock, 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 maintaining our corporate credit rating. We discuss these financial initiatives and the risks facing our business in more detail below.

RETAIL RATES AND ALTERNATIVE REGULATION

Retail Rates Our retail rates are approved by the PSB after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). 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.

On September 30, 2008, the PSB issued an order approving, with modifications, the alternative regulation plan proposal that we submitted in August 2007. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension. The plan replaces the traditional ratemaking process and allows for quarterly rate adjustments to reflect changes in power supply and transmission-by-others costs ("PCAM" adjustment); annual base rate adjustments to reflect changing costs; and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity will be adjusted annually to reflect one-half of the change in the average yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The earnings sharing adjustment mechanism ("ESAM") within the plan provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to ratepayers in a future period. If the actual return on equity of our regulated business falls between 75 and 100 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and ratepayers. Any earnings shortfall in excess of 100 basis points below the allowed return on equity is recovered from ratepayers. These adjustments are made at the end of each fiscal year.

The PCAM and ESAM adjustments are not subject to PSB suspension, but the PSB may open an investigation and, to the extent it finds, after notice and hearing, that a calculation in the adjustments was inaccurate or reflects costs inappropriate for inclusion in rates, it may require a modification of the associated adjustments to the extent necessary to correct the deficiencies.

On October 31, 2008, we submitted a base rate filing for the rate year commencing January 1, 2009 that reflected a 0.33 percent increase in retail rates. The result of the return on equity adjustment for 2009, in accordance with the plan, was a reduction of 0.44 percent, resulting in an allowed return on equity for 2009 of 9.77 percent. On November 17, 2008, the DPS filed a request for suspension and investigation of our filing. Citing concerns about staffing levels and inadequate supporting documentation for some proposed rate base additions, the DPS recommended a 0.43 percent rate decrease.

On December 17, 2008, we filed a Memorandum of Understanding with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our 2009 retail rates. Pursuant to the Memorandum of Understanding, we agreed to leave rates unchanged, with no increase or decrease, and that we and the DPS would request the PSB to open a docket to resolve the DPS's concerns regarding our level of staffing. On February 13, 2009, the PSB approved the Memorandum of Understanding, and ordered the rate investigation closed.

On February 2, 2009, we filed a motion with the PSB requesting to defer the incremental 2008 storm costs through our alternative regulation plan and collect them in rates through the ESAM over 12 months beginning on July 1, 2009. On February 3, 2009, the DPS filed a letter supporting our motion and on February 12, 2009, the PSB approved the request. The amount of the deferral, based on actual costs, was $3.2 million.

On May 1, 2009, we filed an ESAM report, including supporting documentation, with the PSB requesting that rates be increased 1.15 percent for 12 months beginning with bills rendered July 1, 2009 to recover the $3.2 million of incremental 2008 storm costs. On June 15, 2009, the DPS recommended that the ESAM report be approved as filed. On June 30, 2009, the PSB accepted the DPS recommendation and approved the filing. The rate increase has been implemented as proposed.

The PCAM adjustments for the first, second and third quarters of 2009 were calculated to be over-collections of $0.6 million, $0.5 million and $0.6 million, respectively and each was recorded as a current liability. We filed PCAM reports each quarter, including supporting documentation, with the PSB identifying the over-collections. In each case, the DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. The first and second quarter over-collections were returned to customers over the three months ending September 30, 2009 and December 31, 2009, respectively. The third quarter over-collection is being returned to customers over the three months ending March 31, 2010.

The fourth quarter 2009 PCAM adjustment was calculated to be an over-collection of $1.0 million and is recorded as a current liability at December 31, 2009. On January 29, 2010, we filed a PCAM report, including supporting documentation, with the PSB outlining the over-collection. The over-collection will be returned to customers over three months ending June 30, 2010.

On October 30, 2009, we submitted a base rate filing ("2010 base rate filing") for the rate year commencing January 1, 2010, reflecting an increase in revenues of $16.6 million or a 5.91 percent increase in retail rates. Under our alternative regulation plan, the annual change in the non-power costs, as reflected in our base rate filing, is limited to any increase in the U.S. Consumer Price Index for the northeast ("CPI-NE"), less a 1 percent productivity adjustment. The non-power costs associated with the implementation of our asset management plan are excluded from the non-power cost cap. Our 2010 non-power costs exceeded the non-power cost cap by approximately $1 million and these costs ("disallowed costs") will not be included in our 2010 non-power base rates. These disallowed costs will be factored into the earnings-sharing adjustment mechanism when it is calculated after the close of rate year 2010. The allowed rate of return for 2010, calculated in accordance with the plan, will be 9.59 percent.

On December 16, 2009, the DPS notified the PSB that they disagreed with the calculation of the CPI-NE factor in our 2010 base rate filing. The DPS believed we should have used a CPI-NE factor of negative 0.7 percent rather than zero, which would reduce the increase in revenues to $15.6 million or a 5.58 percent increase in retail rates.

On December 22, 2009, we filed an amended 2010 base rate filing with the PSB. The amended filing reflected a CPI-NE factor of negative 0.7 percent and requested an increase of $15.6 million or a 5.58 percent increase in retail rates effective with bills rendered January 1, 2010.

On December 31, 2009, the PSB issued its order approving a rate increase of 5.58 percent effective for bills rendered on January 1, 2010. Prior to this increase, our rates had increased just 5.4 percent since 1999.

As part of our 2010 base rate filing, we proposed an amendment to the non-power cost cap formula of our alternative regulation plan to allow an adder for new initiatives arising after the effective date of the plan. The DPS was supportive of the proposal, and the 2010 base rate filing increase approved by the PSB included recovery of costs for two new initiatives. However, the PSB has not yet acted on the proposed amendment. If the PSB ultimately decides not to approve the amendment, we will be required to refund approximately $0.5 million to customers.

Using the methodology specified in our alternative regulation plan, we calculated the 2009 return on equity from the regulated portion of our business to be approximately 9.9 percent. We are required to file this calculation with the PSB by May 1, 2010. No ESAM adjustment was required since this return was within 75 basis points of our 2009 allowed return on equity of 9.77 percent.

Staffing Level Investigation On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS. On March 25, 2009, the PSB convened a prehearing conference where we and the DPS agreed to a procedural schedule. We and the DPS further agreed that the scope of the technical hearings could be narrowed to devising a methodology for deriving productivity measures that would be tracked over time. The parties did not agree, however, as to what the substantive elements of that tracking methodology should be. Accordingly, the PSB ordered that the purpose of hearings in this proceeding would be to resolve this disagreement about the makeup of the productivity tracking methodology. Technical hearings were held in June 2009 and legal briefs were filed in July 2009.

The PSB issued its Order in the case on August 20, 2009. In its decision, the board made no determination that we are over-staffed. We were allowed to increase our 2010 non-power cost cap by $0.2 million, representing the average cost of an additional 2.25 employees beyond the number that had been allowed in rates. As recommended by the 2008 business process review report, the PSB order requires us to undertake a comprehensive review of our organizational structure, staffing levels and costs to determine the appropriate structure and number of staff we should employ at ratepayer expense.

On November 30, 2009, we filed a Memorandum of Understanding ("Staffing MOU") with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our staffing levels. Under the Staffing MOU, in lieu of retaining a management consultant to perform a comprehensive review of our organizational structure and staffing, we and the DPS have agreed that we will reduce our staffing levels over a five-year period by a total of 17 positions as compared to the 549 positions we had on January 1, 2009. This reduction shall be in addition to the staffing changes contemplated to result from the implementation of CVPS SmartPower™. We retain discretion as to how to achieve the staffing reductions, and the DPS has agreed that it shall not oppose the recovery in rates of all reasonable costs associated with staffing and related compensation during the term of the Staffing MOU, provided that recovery of such costs is otherwise consistent with normal ratemaking standards. Nothing in the Staffing MOU precludes us from seeking to add staff as reasonably necessary in response to new requirements imposed by the state or federal government. The PSB has not yet acted on the MOU.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Cash Flows At December 31, 2009, we had cash and cash equivalents of $2.1 million and at December 31, 2008, we had cash and cash equivalents of $6.7 million.

Our primary uses of cash in 2009 included capital expenditures, investments in affiliates, common and preferred dividend payments, retirement of debt, interest expense and long-term debt payments, and contributions to the pension and postretirement medical plans. Our primary sources of cash in 2009 were from our electric utility operations, net proceeds from our revolving credit facility and distributions received from affiliates.

Operating Activities: Operating activities provided $42.1 million in 2009, compared to $28.4 million in 2008. The increase of $13.7 million was primarily due to an increase in earnings and income tax refunds received in 2009. In the first quarter of 2009, we received $6.5 million of income tax refunds resulting from our election of federal bonus depreciation on our assets as well as our share of Transco assets placed in service during 2008.

At December 31, 2009, our retail customers' accounts receivable over 60 days was $2.5 million and was $2.7 million at December 31, 2008, which was a decrease of 5.4 percent.

The decrease in cash from operating activities from 2007 to 2008 was due primarily to an increase in special deposits and restricted cash for power collateral, working capital and other items; partially offset by higher distributions received from affiliates, most materially from our investments in Transco.

Investing Activities: Investing activities used $52.9 million in 2009, compared to $40.5 million in 2008. The increase of $12.4 million was primarily due to our $20.8 million equity investment in Transco in December 2009, partially offset by a decrease in construction and plant expenditures given a large transmission project in 2008. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements.

The increase in cash from investing activities from 2007 to 2008 was primarily due to a lower level of investing in Transco in 2008; partially offset by higher construction and plant expenditures in 2008.

Financing Activities: Financing activities provided $6.2 million in 2009, compared to $15 million in 2008. The decrease of $8.8 million was primarily due to the 2008 issuances of $23.5 million of common stock and $60 million of first mortgage bonds, partially offset by the repayment of a $53 million short-term bridge loan in 2008. In 2009, we received $23.3 million of net proceeds from our revolving credit facility.

The decrease in cash from financing activities from 2007 to 2008 was primarily due to the 2008 issuances of $23.5 million of common stock vs. $53 million of proceeds received in 2007 from the short-term bridge loan. Also, see Financing below.

Transco In December 2009, we invested an additional $20.8 million in Transco and our direct ownership interest increased from 33.02 percent to 33.35 percent as a result of additional member contributions from Vermont utilities. Our total direct and indirect interest in Transco decreased from 39.67 percent to 38.68 percent.

In December 2008, we invested an additional $3.1 million in Transco and our direct ownership interest decreased from 39.79 percent to 33.02 percent as a result of additional member contributions from Vermont utilities primarily related to specific facilities. Our total direct and indirect interest in Transco decreased from 45.68 percent to 39.67 percent.

Based on current projections, Transco expects to need additional equity capital in 2010 and 2011, 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, which are subject to available capital and appropriate regulatory approvals, 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 of up to $43.5 million in 2010 and $11.5 million in 2011, 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. These capital investments in Transco and the core business provide value to customers and shareholders alike. They provide shareholders with a return on investment, while helping to improve and maintain reliability for our customers.

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 has been using Treasury shares as the source of common shares to meet reinvestment obligations since July 2007. These elections are expected to result in additional cash flow of $1 million to $2 million annually. In September 2009, we ceased using Treasury shares and began using original issue shares to meet reinvestment obligations under the plan.

Customer Bankruptcy On October 26, 2009, a major telecommunications customer filed for bankruptcy protection. In 2009, this customer received electric services totaling $2.1 million and as of December 31, 2009, our accounts receivable includes an estimate of the net realizable amount. We are unable to predict the outcome of this matter at this time or its impact on our financial statements.

Cash Flow Risks Based on our current cash forecasts, we will require outside capital in addition to cash flow from operations and our $40 million and $15 million unsecured revolving credit facilities in order to fund our business over the next few years. Prolonged upheaval in the capital markets could negatively impact our ability to obtain outside capital on reasonable terms. If we were ever unable to obtain needed capital, we would re-evaluate and prioritize our planned capital expenditures and operating activities. 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. An extended Vermont Yankee plant outage could involve cost recovery via our forced outage insurance policy and recoveries under the PCAM but in general would not be expected to materially impact our financial results, if the costs are recovered in retail rates in a timely fashion. 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. It is important to note, however, that our alternative regulation plan sets bands around the earnings in our regulated business, which ensures, in part, that they will not fall below prescribed levels. See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks.See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks.

Global Economic Crisis Due to the global economic crisis, there was a significant decline in lending activity beginning in 2008, which has recently begun to abate. We expect to have access to liquidity in the capital markets when needed at reasonable rates. We have access to a $40 million unsecured revolving credit facility and a $15 million unsecured revolving credit facility with two different lending institutions. However, sustained turbulence in the global credit markets could limit or delay our access to capital. As part of our enterprise risk management program, we routinely monitor our risks by reviewing our investments in and exposure to various firms and financial institutions.

Financing

Long-Term Debt: Substantially all of our utility property and plant are subject to the lien under our First Mortgage Indenture. Associated scheduled sinking fund and maturity payments for the next five years are: zero in 2010, $20 million in 2011, zero in 2012, $5.8 in 2013 and zero in 2014. Currently, we are in compliance with the terms of all of our debt financing documents.

Credit Facility: We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a credit agreement dated November 3, 2008. 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 0.15 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.7 percent on the average daily amount of letters of credit outstanding. All interest, commission and fee rates are based on our unsecured issuer rating. The facility contains a material adverse effect clause, which permits the lender to deny a transaction at the point of request. We are also required to collateralize any outstanding letter of credit in the event of a default under the credit facility. At December 31, 2009, $23.3 million in loans and no letters of credit were outstanding under the credit facility.

We also have a 364-day, $15 million unsecured revolving credit facility with a different lending institution pursuant to a credit agreement dated December 30, 2009. The purpose and obligation under this credit agreement are the same as described above. Financing terms and costs include an annual commitment fee of 0.5 percent on the unused facility balance, and commission of 2 percent per year on the average daily amount of letter of credit outstanding. Interest on the outstanding balance of amounts borrowed under various interest options is based on our unsecured issuer rating. The facility does not contain a material adverse effect clause or the requirement to collateralize any outstanding letter of credit in the event of a default under the credit facility. At December 31, 2009, there were no borrowings or letters of credit outstanding under the credit facility.

Letters of Credit: We have two outstanding unsecured letters of credit, issued by one bank, that support the Connecticut Development Authority ("CDA") and Vermont Industrial Development Authority ("VIDA") revenue bonds. These letters of credit total $11.1 million in support of two separate issues of industrial development revenue bonds totaling $10.8 million. We pay an annual fee of 2.4 percent on the letters of credit, based on our unsecured issuer rating. These letters of credit expire on November 30, 2012. The letters of credit contain cross-default provisions to our wholly owned subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or insolvency. At December 31, 2009, there were no amounts drawn under these letters of credit.

Revenue Bonds: Because of the three-year term of the new letters of credit discussed above, the VIDA and CDA revenue bonds have been reclassified from Notes Payable to Long-Term Debt in the 2009 financial statements.

Refinancing Plans: We are currently reviewing options to issue debt and equity to support working capital requirements resulting from investments in our distribution and transmission system. On November 6, 2009, we filed a Registration Statement on Form S-3 with the SEC requesting the ability to offer, from time to time and in one or more offerings, up to $55 million of our common stock. On December 4, 2009, the SEC declared the Registration Statement to be effective. On January 15, 2010, we filed a Prospectus Supplement with the SEC noting that we entered into an Equity Distribution agreement allowing us to issue up to $45 million of shares under an "at-the-market" offering program. As of December 31, 2009, no shares have been issued under this arrangement.

Covenants: At December 31, 2009, we were in compliance with all financial and non-financial covenants related to our various debt agreements, articles of association, letters of credit, credit facilities and material agreements. Some of the typical covenants include:

- The timely payment of principal and interest;
- Information requirements, including submitting financial reports filed with the SEC to lenders;
- Performance obligations, audits/inspections, continuation of the basic nature of business, restrictions on certain matters related to merger or consolidation, restrictions on disposition of all or substantially all of our assets;
- Limitations on liens;
- Limits on the amount of additional debt (short- and long-term) and equity that can be issued;
- Restrictions on the payment of dividends and optional stock redemptions, or the making of certain investments, loans, guarantees, and acquisitions in the absence of a waiver; and
- Maintenance of certain financial ratios.

These are usual and customary provisions, not necessarily unique to us. If we were to default on any of our covenants in the absence of a waiver or amendment, the lenders could take actions such as terminating their obligations, declaring all amounts outstanding or due immediately payable, or taking possession of or foreclosing on mortgaged property. Substantially all of our utility property and plant is subject to liens under our First Mortgage Bond indenture.

The most restrictive of our maintenance covenants is a first mortgage bond interest coverage test. We are required to maintain earnings at a two times interest coverage. At December 31, 2009, our earnings covered our first mortgage bond interest 3.9 times. At December 31, 2009, we had the ability to declare $75.7 million additional dividends or other restricted payments. Also, at December 31, 2009, we were permitted to incur $38.8 million of additional mortgage bond debt and $102.5 million of unsecured debt, of which only $88.3 million could be short-term.

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system. Capital expenditures in 2009 amounted to $31.4 million. Capital expenditures for the next five years are expected to range from $37 million to $53 million annually, including an estimated total of more than $60 million for CVPS SmartPower™ over the five-year period. On October 27, 2009, the U.S. Department of Energy ("DOE") announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation. As a participant on Vermont's smart grid stimulus application, we expect to receive a grant of over $31 million. This award will fund a portion of the SmartPower project total discussed above and is reflected in the five-year capital expenditure estimates above. We are now negotiating with the DOE and other Vermont utilities to finalize funding and requirements. The 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, 2009 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 (a)	$201.6	$0.0	$43.3	$5.8	$152.5
Interest on long-term debt (b)	153.5	11.1	20.4	19.7	102.3
Redeemable preferred stock	1.0	1.0	0.0	0.0	0.0
Capital lease (c)	6.5	1.4	2.4	2.0	0.7
Operating leases - vehicle and other (d)	7.0	1.8	3.1	1.8	0.3
Purchased power contracts (e)	635.2	144.3	246.1	140.2	104.6
Nuclear decommissioning and other closure costs (f)	8.5	1.4	3.2	2.9	1.0
Other purchase obligations (g)	0.7	0.7	0.0	0.0	0.0
Total Contractual Obligations	$1,014.0	$161.7	$318.5	$172.4	$361.4

(a) Our credit facilities, debt agreements, letters of credit and articles of association contain customary covenants and default provisions. Non-compliance with certain covenants such as timely payment of principal and interest may constitute an event of default, which could cause an acceleration of principal payments in the absence of a waiver or amendment. Such acceleration would change the obligations outlined in the Contractual Obligations table.

(b) Based on interest rates shown in Part II, Item 8, Note 13 - Long-Term Debt, Notes Payable and Credit Facility.

(c) Includes interest payments based on imputed fixed interest rates at inception of the related leases.

(d) Includes interest payments on fixed rates at inception and floating rate issues based on interest rates as of December 31, 2009.

(e) 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, market power prices and availability of the transmission system; therefore, actual results may differ. See Power Supply Matters for more information.

(f) 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.

(g) Amount represents open purchase orders, excluding those obligations that are separately reported. These payments are subject to change as certain purchase orders include estimates of material and/or services. Because payment timing cannot be determined, we include all open purchase order amounts in 2010. These amounts are not included on our Consolidated Balance Sheet.

Pension and Postretirement Medical Benefit Obligations: The contractual obligation table above excludes estimated funding for the pension obligation reflected in our Consolidated Balance Sheet. In 2010, pending further review, we expect to contribute a total of $6.3 million to our pension and postretirement medical trust funds. Based on our current policy to fund at the actuarial expense level, we expect that pension and postretirement medical contributions could increase by approximately 30 percent by 2013, primarily due to the amortization of 2008 market losses. These payments may also vary based on changes in the fair value of plan assets and actuarial assumptions. Traditionally, we have recovered these costs through rates. Additional obligations related to our nonqualified pension plans are approximately $0.2 million per year.

Income Taxes: At December 31, 2009, we did not have any uncertain tax position obligations that will result in future cash outflows.

Capitalization Our capitalization for the past two years follows:

	(dollars in thousands)		percent	
	2009	2008	**2009**	2008
Common stock equity	231,423	$219,479	52%	55%
Preferred stock	8,054	9,054	2%	2%
Long-term debt	201,611	167,500	45%	42%
Capital lease obligations	4,313	5,173	1%	1%
	$445,401	$401,206	100%	100%

Credit Ratings On December 4, 2009, Moody's Investors Service ("Moody's") assigned a Baa3 corporate credit rating (an investment-grade rating), assigned a Baa1 senior secured bond rating and affirmed our current Ba2 preferred stock rating. At the same time, Moody's affirmed our stable rating outlook. Prior to December 4, 2009, we were rated by Standard & Poor's Ratings Services ("S&P"). On December 10, 2009, S&P withdrew its ratings of CVPS at our request. Our current credit ratings from Moody's are shown in the table below. Credit ratings should not be considered a recommendation to purchase or sell stock.

Issuer Rating	Baa3
First Mortgage Bonds	Baa1
Preferred Stock	Ba2
Outlook	Stable

Our credit ratings are influenced by our levels of cash flow and debt, and other factors published by Moody's. If our corporate credit rating were to decline to a non-investment-grade level, we could be asked to provide additional collateral in the form of cash or letters of credit primarily under our power contracts or power transactions through ISO-New England. While our credit facilities are sufficient in amounts that would be required to meet collateral calls at a higher level, our ability to meet any future collateral calls would depend on our liquidity and access to bank credit lines and the capital markets at such time. Additionally, a decline in our corporate credit rating could jeopardize our ability to secure power contracts, including the replacement of our long-term power contracts, at reasonable terms. Maintaining our investment-grade ratings is a top priority for us, and Moody's has provided clear credit metrics and guidelines used in their consideration of our credit ratings.

Performance Assurance At December 31, 2009, we had posted $5.4 million of collateral under performance assurance requirements for certain of our power contracts, all of which was represented by restricted cash. We are subject to performance assurance requirements through ISO-New England under the FERC-filed tariff and Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $2.7 million with ISO-New England. This is a marked improvement from the past. Prior to the receipt of our current ratings from Moody's, our below-investment-grade ratings meant we had a credit limit of zero with ISO-New England, and were required to post collateral for net purchases. We are now required to post collateral for only net purchased power transactions in excess of our new credit limit. 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 ("Entergy-Vermont Yankee"), the seller, has commercially reasonable grounds to question our ability to pay for monthly power purchases, Entergy-Vermont Yankee 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. We lease our vehicles and related equipment under operating lease agreements. These operating lease agreements are described in Part II, Item 8, Note 17 - Commitments and Contingencies.

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 equity interests in VELCO and Transco, which require us to pay a portion of their operating costs under our transmission agreements. We own an equity interest in VYNPC and are obligated to pay a portion of VYNPC's operating costs under the PPA. We also own equity interests in three nuclear plants that have completed decommissioning. We are responsible for paying our share of the costs associated with these plants. Our equity ownership interests are described in Part II, Item 8, Note 3 - Investments in Affiliates.

On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). 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 Part II, Item 8, Note 17 - Commitments and Contingencies.

OTHER BUSINESS RISKS
Our Enterprise Risk Management ("ERM") program serves to protect our assets, safeguard shareholder investment, ensure compliance with applicable legal requirements and effectively serve our customers. The ERM program is intended to provide an integrated and effective governance structure for risk identification and management and legal compliance within the company. Among other things, we use metrics to assess key risks, including the potential impact and likelihood of the key risks.

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. Accordingly, 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 Policy Initiatives below.

Power Supply Risk: Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that the plant could be shut down earlier than expected if Entergy-Vermont Yankee determines that it is not economical to continue operating the plant, or due to environmental concerns. Hydro-Quebec contract deliveries end in 2016, but the average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 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. However, the company has been planning for the expiration of these contracts for several years, and a robust effort, described further below, is in place to ensure a safe, reliable, environmentally beneficial and relatively affordable energy supply going forward.

Entergy-Vermont Yankee has submitted a renewal application with the NRC and an application for a Certificate of Public Good ("CPG") with the PSB for a 20-year extension of the Vermont Yankee plant operating license. Entergy-Vermont Yankee also needs approval from the PSB and Vermont Legislature to continue to operate beyond 2012. Significant hurdles may prevent its relicensing. Potential operating, transparency and communication issues related to the plant and its operations have raised serious concerns among regulators and members of the Vermont Legislature, including some who have called for its temporary or permanent shutdown. An intervenor in the CPG case has requested that the PSB order a shutdown of the Vermont Yankee plant pending resolution of current tritium leaks at the site. The PSB has opened a new docket to consider that request. We are unable to predict the outcome of this matter.

On February 24, 2010, in a non-binding vote, the Vermont Senate voted against allowing the PSB to consider granting the Vermont Yankee plant another 20-year operating license after 2012. A new Vermont legislature will be elected in the fall of 2010 and could vote differently. We are unable to predict the outcome of this matter.

At this time, Entergy-Vermont Yankee is attempting to overcome these concerns, but we have not held any formal negotiations on a new contract since these issues arose in January. We rejected Entergy-Vermont Yankee's current proposal, but both parties are prepared to resume negotiations for a purchased power contract when the issues that have emerged are resolved. We cannot predict the outcome 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, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.5 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 such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results, if the costs are recovered in retail rates in a timely fashion.

To mitigate these risks, beginning in 2007, we, Green Mountain Power, and HQ-Production created a steering committee structure to develop background materials, terms and supporting actions needed in negotiations for future power purchases from Hydro-Quebec. Beginning in May 2008, HQ-Production also engaged with Northeast Utilities ("NU") and NSTAR on a plan to bundle a new 1,200 MW New England/Quebec interconnection and power purchase agreement and have submitted the concept to the FERC for approval. HQ-Production and NU have expressed the expectation that there will be sufficient volume in that bundled power purchase agreement to allow the participation of other load-serving New England utilities to participate, including Vermont utilities. The Vermont utilities now expect to join in the negotiations of the agreement, which are scheduled to continue in 2010. Agreements to renew purchases over existing interconnections are also possible. We recently signed a memorandum of agreement, a precursor to a final contract for ongoing Hydro-Quebec supplies. We cannot predict whether a new contract will ultimately be achieved and approved or if approved, the quantities of power to be purchased or the price terms of any purchases. However, we view the signing of this memorandum as a positive step toward continuation of our decades-long relationship with Hydro-Quebec and for the good of Vermont's consumers.

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. We have forced outage insurance through March 21, 2011 to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The Power Cost Adjustment Mechanism within our alternative regulation plan allows recovery of power costs.

Market Risk: See Part II, 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 the financial statements for our utility operations in accordance with Financial Accounting Standards Board ("FASB") guidance for regulated operations. 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. In some circumstances, 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 for regulated operations and there is not a rate mechanism to recover these costs, the impact would, among other things, be a charge to operations of $11.8 million pre-tax at December 31, 2009. The continued applicability of accounting for regulated operations is assessed at each reporting period. We believe our regulated operations will be subject to this accounting guidance for the foreseeable future. Also, see Recent Accounting Pronouncements below.

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 2009 or 2008.

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 5.2 percent. A 1 percent change in line losses would result in a $2.8 million change in annual revenues. Factors that could affect the estimate of unbilled revenues include 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 $20.8 million at December 31, 2009 and $18.5 million at December 31, 2008. We believe that these assumptions have resulted in a reasonable approximation of our unbilled revenues and are reasonably likely to continue.

Allowance for Uncollectible Accounts We record allowances for uncollectible accounts based on customer-specific analysis, current assessments of past due balances and economic conditions, and historical experience. Additional allowances for uncollectible accounts may be required if there is deterioration in past due balances, if economic conditions are less favorable than anticipated, or for customer-specific circumstances, such as financial difficulty or bankruptcy. In 2009, our allowance for uncollectible accounts was $3.6 million, compared to $2.2 million in 2008. The increase was largely due to a major telecommunications customer bankruptcy.

Pension and Postretirement Medical Benefits FASB's accounting guidance for employee retirement benefits 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.

The guidance also required 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 estimated that changing the annual benefit measurement date from September 30 to December 31 would result in a pre-tax charge of $1.3 million, of which $0.1 million was recorded to retained earnings. We received PSB approval for recovery of the regulated utility portion of the impact resulting from the change in measurement date. Accordingly, we recorded a regulatory asset of $1.2 million in the first quarter of 2008 that is being 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 future 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 December 31 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 million in par value. As of December 31, 2009, the pension discount rate changed from 6.15 percent to 6 percent and the postretirement medical discount rate changed from 6.05 percent to 5.5 percent. The conditions in the credit market have been volatile since the third quarter of 2008, and decreases in the discount rates could increase our benefit obligations, which may also result in higher costs and funding requirements.

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 long-term assumption was 7.85 percent as of December 31, 2008 and December 31, 2009. This rate was also used to determine the annual expense for 2009 and will be used to determine the 2010 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 the measurement date in 2008 and 2009.

Health Care Cost Trend: We project expected increases in the cost of health care. We are self-insured, and in recent years have managed costs such that the increases we have experienced have been below the increases on a national level. For measuring annual cost, we assumed a 9.0 percent annual rate of increase in the per capita cost of covered health care benefits for fiscal 2009, for pre-age 65 and post-age 65 participant claims costs. The rate is assumed to decrease 0.5 percent each year, when an ultimate rate of 5 percent is reached in 2017.

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 Part II, Item 8, Note 15 - 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 and other postretirement medical benefit costs (dollars in thousands):

	Discount Rate		Return on Assets	
	Increase	**Decrease**	**Increase**	**Decrease**
Pension Plan				
Effect on projected benefit obligation as of December 31, 2009	($1,909)	$1,946	$0	$0
Effect on 2009 net period benefit cost	($3)	($2)	($265)	$265
Other Postretirement Medical Benefit Plans				
Effect on accumulated postretirement benefit obligation as of December 31, 2009	($625)	$639	$0	$0
Effect on 2009 net periodic benefit cost	($83)	$84	($25)	$25

Fair Value Measurements We adopted the fair value guidance issued by FASB on January 1, 2008. The fair value guidance establishes criteria to be considered when measuring the fair value of assets and liabilities and expands disclosures about fair value measurements, but it does not expand the use of fair value accounting in any new circumstances. We adopted the application of fair value related to our asset retirement obligations on January 1, 2009, as permitted. Adoption of the fair value guidance did not have a material impact on our financial position, results of operations or cash flows.

A fair value hierarchy is used to prioritize the inputs included in valuation techniques. The hierarchy is designed to indicate the relative reliability of the fair value measure. The highest priority is given to quoted prices in active markets, and the lowest to unobservable data, such as an entity's internal information. The lower the level of the input of a fair value measurement, the more extensive the disclosure requirements. The three broad levels include: quoted prices in active markets for identical assets or liabilities (Level 1); significant other observable inputs (Level 2); and significant unobservable inputs (Level 3).

Our assets and liabilities that are recorded at fair value on a recurring basis include cash equivalents and restricted cash consisting of money market funds, power-related derivatives and our Millstone decommissioning trust. Money market funds are classified as Level 1. Power-related derivatives are classified as Level 3. The Millstone decommissioning trust funds include treasury securities, other agency and corporate fixed income securities and equity securities that are classified as Level 1 and Level 2. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

At December 31, 2009, the fair value of money market funds was $0.7 million, the fair value of restricted cash was $5.4 million and the fair value of decommissioning trust assets was $5.1 million. The fair value of power-related derivatives was a net unrealized gain of $0.2 million at December 31, 2009. This included unrealized gains of $0.6 million and unrealized losses of $0.4 million. See Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk for additional information about power-related derivatives.

Derivative Financial Instruments We account for various power contracts as derivatives under the provisions of FASB's guidance for derivatives and hedging. This guidance requires 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. The value of each forward energy derivative contract, measured over its entire duration, is primarily based on the difference between contract prices and non-binding broker quotes provided from a paid pricing service, consistent with industry practice. Price information for forward energy derivative contracts is not readily observable in the market. Based on management discussions with the broker concerning development of price quotes, information has been considered including prices from other similar contracts. Since this information is not publicly quoted or readily observable, we have assessed our forward energy derivatives as Level 3 fair value measures. 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 all power contract derivatives as deferred charges or deferred credits on the balance sheet, depending on whether the change in 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 of the contracts.

During 2009, we entered into two forward power contracts that we classify as derivatives. At December 31, 2009, the estimated fair value of all power contract derivatives was a net unrealized gain of $0.2 million ($0.6 million unrealized gain and $0.4 million unrealized loss). In 2008, we also had several forward power contracts that were derivatives. At December 31, 2008, the estimated fair value of all power contract derivatives was a net unrealized gain of $8.8 million ($12.9 million unrealized gain and $4.1 million unrealized loss). Also see Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

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 cost estimate for the third site is less than $0.1 million. The liability estimate includes costs for remediation, monitoring and other future activities. At December 31, 2009, our reserve for the three sites was $1.6 million and it was $1.7 million at December 31, 2008. 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.

In December 2009, we voluntarily submitted results of internally tested soil samples from two additional locations to the State of Vermont Sites Management Section ("SMS"). These soil sample results showed contamination at levels of concern to SMS. As a result, SMS has listed these sites as active hazardous waste sites and requested that we complete additional testing at these properties. Although management does not believe there is significant contamination at these sites, the extent and cost of potential remediation will not be known until the additional testing is completed during 2010.

Reserve for Loss on Power Contract In 2005, we established a reserve for a loss on a terminated power sales agreement in connection with the sale of a subsidiary's franchise. The reserve is being amortized on a straight-line basis through 2015 as the cash is paid out under the underlying supply contracts. The amortization is being credited to purchase power expense on the Consolidated Statement of Income. The balance of the reserve was $7.2 million at December 31, 2009 and $8.4 million at December 31, 2008.

Income Taxes We follow FASB's guidance and methodology for 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. We record income tax expense quarterly using an estimated annualized effective tax rate. Adjustments to these estimates and changes in our subjective assumptions and judgments can materially affect amounts recognized on the income statement, balance sheet and statement of cash flows.

Other See Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies for a discussion of newly adopted accounting policies and recently issued accounting pronouncements.

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 Our consolidated earnings for 2009 were $20.7 million, or $1.74 per diluted share of common stock. This compares to 2008 consolidated earnings of $16.4 million, or $1.52 cents per diluted share of common stock and 2007 consolidated earnings of $15.8 million, or $1.49 cents per diluted share of common stock.

The tables that follow provide a reconciliation of the primary year-over-year variances in diluted earnings per share for 2009 versus 2008 and 2008 versus 2007. The earnings per diluted share for each variance shown below are non-GAAP measures:

	2009 vs. 2008
2008 Earnings per diluted share	**$1.52**
Year-over-Year Effects on Earnings:	
Lower purchased power expense	0.42
Higher equity in earnings of affiliates	0.09
Higher transmission expense	(0.32)
Common stock issuance (Nov. 2008) - 1,190,000 additional shares (a)	(0.18)
Higher other operating expenses	(0.02)
Other (mostly variable life insurance)	0.23
2009 Earnings per diluted share	**$1.74**

(a) Additional average shares from the November 2008 stock issuance were excluded from the 11,705,518 average shares of common stock - diluted, for the purposes of computing the individual EPS variances shown above in order to provide comparable information for 2009 vs. 2008.

	2008 vs. 2007
2007 Earnings per diluted share	**$1.49**
Year-over-Year Effects on Earnings:	
Higher operating revenues	0.73
Higher equity in earnings of affiliates	0.54
Higher purchased power expense	(0.27)
Higher transmission expense	(0.25)
Higher interest expense	(0.17)
Higher other operating expenses	(0.21)
Other	(0.34)
2008 Earnings per diluted share	**$1.52**

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 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 price of those sales. Operating revenues and related mWh sales are summarized below.

	Revenues (in thousands)			mWh Sales		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Residential	**$139,047**	$138,091	$136,359	**981,838**	982,966	1,003,055
Commercial	**104,001**	108,252	107,556	**825,010**	873,192	885,713
Industrial	**32,597**	34,858	36,064	**364,516**	396,741	425,356
Other	**1,884**	1,872	1,840	**6,398**	6,312	6,250
Total retail sales	**277,529**	283,073	281,819	**2,177,762**	2,259,211	2,320,374
Resale sales	**54,279**	48,641	38,935	**840,536**	759,832	697,749
Provision for rate refund	**(1,689)**	(296)	(747)	**0**	0	0
Other operating revenues	**11,979**	10,744	9,100	**0**	0	0
Total operating revenues	**$342,098**	$342,162	$329,107	**3,018,298**	3,019,043	3,018,123

The average number of retail customers is summarized below:

	2009	**2008**	**2007**
Residential	**136,242**	136,074	135,591
Commercial	**22,577**	22,407	22,106
Industrial	**36**	35	37
Other	**175**	175	175
Total	**159,030**	158,691	157,909

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

	2009 vs. 2008	2008 vs. 2007
Retail sales:		
Volume (mWh)	**($8,937)**	($6,660)
Average price due to customer sales mix	**2,532**	2,194
Average price due to rate increases	**861**	5,720
Subtotal	**(5,544)**	1,254
Resale sales	**5,638**	9,706
Provision for rate refund	**(1,393)**	451
Other operating revenues	**1,235**	1,644
Change in operating revenues	**($64)**	$13,055

2009 vs. 2008

Operating revenues decreased by $0.1 million, or less than 1 percent, due to the following factors:

- Retail sales decreased $5.5 million resulting from lower sales volume, partly offset by higher average retail rates and a higher average price due to customer sales mix. Sales volume decreased due to lower usage by commercial and industrial customers resulting from economic conditions.
- Resale sales increased $5.6 million as a result of higher sales volume due to lower retail sales volume and increased output from power producers. Average prices for forward sales increased while prices for hourly sales decreased.
- In 2009, the provision for rate refund is related to over-collections of $1.7 million of power, production and transmission costs as defined by the power cost adjustment clause of our alternative regulation plan.
- Other operating revenues increased $1.2 mostly from sales of additional transmission capacity from our share of Phase I/II transmission facility rights, an increase in wholesale transmission rates and the sale of renewable energy credits. We began selling transmission capacity in April 2007, and we have the ability to restrict the amount of capacity assigned to the purchasers based on certain conditions.

2008 vs. 2007

Operating revenues increased $13.1 million, or 3.97 percent, due to the following factors:

- Retail sales increased $1.3 million resulting from a 2.3 percent rate increase effective February 1, 2008 and a higher average price due to customer sales mix. Retail sales volume was lower in 2008 largely due to lower average usage caused by milder weather, a slowing economy and energy conservation.
- Resale sales increased $9.7 million resulting from higher average prices and an increase in excess power available for resale due to lower retail sales volume, higher output from our hydro facilities and Independent Power Producers and less lost output from unplanned outages at Vermont Yankee.
- The provision for rate refund, which is a reduction in operating revenues, is related to amounts that were included in retail rates in 2007 and January 2008 that were to be refunded to customers. The provision for refund ended with new retail rates effective February 1, 2008 that reflect the customer refund.
- Other operating revenues increased $1.6 million due to sales of transmission rights and increased revenue from storm restoration performed for other utilities, partially offset by a provision for refund to retail customers.

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).

	2009 over/(under) 2008		2008 over/(under) 2007	
	Total Variance	**Percent**	**Total Variance**	**Percent**
Purchased power - affiliates and other	**($7,469)**	**-4.5%**	$4,729	2.9%
Production	**(849)**	**-6.9%**	523	4.5%
Transmission - affiliates	**722**	**9.9%**	2,136	41.5%
Transmission - other	**4,948**	**26.2%**	2,327	14.1%
Other operation	**3,416**	**6.1%**	2,287	4.3%
Maintenance	**(3,780)**	**-13.5%**	55	0.2%
Depreciation	**1,261**	**8.1%**	443	2.9%
Taxes other than income	**1,074**	**6.9%**	513	3.4%
Income tax expense (benefit)	**155**	**3.2%**	(413)	-7.8%
Total operating expenses	**($522)**	**-0.2%**	$12,600	4.0%

Purchased Power - affiliates and other: Power purchases made up 49 percent of total operating expenses in 2009, 51 percent in 2008 and 52 percent in 2007. 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 (in thousands)			mWh purchases		
	2009	2008	2007	**2009**	2008	2007
VYNPC (a)	**$64,017**	$57,708	$55,772	**1,551,925**	1,417,144	1,361,754
Hydro-Quebec	**63,095**	63,670	64,869	**919,764**	937,923	998,411
Independent Power Producers	**22,559**	26,430	22,796	**202,483**	202,193	176,169
Subtotal long-term contracts	**149,671**	147,808	143,437	**2,674,172**	2,557,260	2,536,334
Other purchases	**7,209**	16,877	16,018	**59,037**	165,362	219,186
Loss contingency amortizations	**(1,196)**	(1,196)	(1,196)	**0**	0	0
Nuclear decommissioning	**1,312**	2,070	2,588	**0**	0	0
Other	**986**	(108)	(125)	**0**	0	0
Total purchased power	**$157,982**	$165,451	$160,722	**2,733,209**	2,722,622	2,755,520

(a) Regulatory deferrals of $0.5 million in 2007 and 2008 have been reclassified and included in Other to conform to current year presentation.

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

	2009 vs. 2008	2008 vs. 2007
VYNPC (a)	**$6,309**	$1,936
Hydro-Quebec	**($575)**	(1,199)
Independent Power Producers (IPPs)	**($3,871)**	3,634
Subtotal long-term contracts	**1,863**	4,371
Other purchases	**(9,668)**	859
Nuclear decommissioning	**(758)**	(518)
Other	**1,094**	17
Total purchased power	**($7,469)**	$4,729

(a) Regulatory deferrals of $0.5 million in 2007 and 2008 have been reclassified and included in Other to conform to current year presentation.

2009 vs. 2008

Purchased power expense decreased $7.5 million, or 4.5 percent, due to the following factors:

- Purchased power costs under long-term contracts increased $1.9 million in 2009, due primarily to higher VYNPC output and because there were no plant refueling outages in 2009. This was primarily offset by decreased purchases from IPPs due to the November 2008 expiration of one contract, and lower prices on all market-based purchases.
- Other purchases decreased $9.7 million in 2009 because more power was available from long-term contract sources.

- Nuclear decommissioning costs decreased $0.8 million in 2009 and are associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs are based on FERC-approved tariffs. The decrease is largely due to lower revenue requirements for Connecticut Yankee and Maine Yankee.
- Other costs increased $1.1 million. These Other costs are amortizations and deferrals based on PSB-approved regulatory accounting, and include net accounting deferrals and amortizations for incremental energy costs related to Millstone Unit #3 scheduled refueling outages and deferrals for our share of nuclear insurance refunds received by VYNPC.

<u>2008 vs. 2007</u>
Purchased power expense increased $4.7 million, or 2.9 percent, due to the following factors:

- Purchased power costs under long-term contracts increased $4.4 million in 2008, due primarily to increased purchases from IPPs at higher prices and from increased Vermont Yankee plant output we purchase at favorable rates under the PPA. The Vermont Yankee plant operated at nearly full capacity in 2008 with the exception of a few small derates and the planned refueling outage in the fourth quarter. These increases were offset by fewer purchases from Hydro-Quebec due to a 5 percent decrease in the annual load factor.
- Other purchases increased $0.9 million in 2008 resulting from higher average prices for replacement energy purchased during the Vermont Yankee refueling outage and derate described above.
- Nuclear decommissioning costs decreased $0.5 million in 2008 and are associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs are based on FERC-approved tariffs. The decrease is largely due to lower revenue requirements for Connecticut Yankee and Maine Yankee.

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

The decrease of $0.8 million for 2009 versus 2008 was principally due to $0.6 million of lower premiums for Vermont Yankee forced outage insurance. There were no significant variances for 2008 versus 2007.

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 $0.7 million for 2009 versus 2008 was principally due to higher rates under the VTA, related to the overall transmission expansion in New England, partially offset by higher NOATT reimbursements. The increase of $2.1 million for 2008 versus 2007 was principally due to the same factors.

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 $4.9 million for 2009 versus 2008 primarily resulted from higher rates and overall transmission expansion in New England. The increase of $2.3 million for 2008 versus 2007 was primarily for the same reason.

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 $3.4 million for 2009 versus 2008 was primarily due to $2.2 million of higher net regulatory amortizations, primarily related to the recovery of 2008 major storm costs and $0.5 million of higher reserves for uncollectible accounts, primarily due to a customer bankruptcy, partially offset by lower professional service costs due to a large software project in 2008 that did not recur in 2009.

The increase of $2.3 million for 2008 versus 2007 was primarily related to higher employee-related costs, higher net regulatory amortizations and higher reserves for uncollectible accounts, partially offset by lower professional service costs.

Maintenance: These expenses are associated with maintaining our electric distribution system and include costs of our jointly owned generation and transmission facilities. The decrease of $3.8 million for 2009 versus 2008 was largely due to lower service restoration costs. There were more major storms in 2008 than in 2009.

The increase of $0.1 million for 2008 versus 2007 was largely due to increased storm recovery activity, net of a favorable deferral of $4.1 million of service restoration costs resulting from the ice storm in December 2008.

Depreciation: We use the straight-line remaining-life method of depreciation. The increase of $1.3 million for 2009 versus 2008 was due to a higher level of utility plant assets. There was no significant variance for 2008 versus 2007.

Taxes other than income: This is related primarily to property taxes and payroll taxes. The increase of $1.1 million for 2009 versus 2008 was due to increases in property taxes. There was no significant variance for 2008 versus 2007.

Income tax expense: 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. There was no significant variance for 2009 versus 2008 or for 2008 versus 2007.

The effective combined federal and state income tax rate was 34 percent for 2009, 39.6 percent for 2008 and 29.9 percent for 2007. Also see Part II, Item 8, Note 16 - Income Taxes.

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 $0.9 million in 2009, $0.2 million in 2008 and $0.5 million in 2007. 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).

	2009 over/(under) 2008		2008 over/(under) 2007	
	Total Variance	**Percent**	Total Variance	Percent
Equity in earnings of affiliates	**$1,208**	**7.4%**	$9,834	*
Allowance for equity funds during construction	**(167)**	**-50.9%**	281	*
Other income	**(663)**	**-18.4%**	(215)	-5.6%
Other deductions (primarily variable life insurance)	**3,220**	**-67.0%**	(2,324)	93.7%
Income tax expense	**222**	**-3.8%**	(4,404)	*
Total other income and deductions	**$3,820**	**40.1%**	$3,172	49.9%

* 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 $1.2 million for 2009 versus 2008 is principally due to the $3.1 million investment that we made in Transco in December 2008. The increase of $9.8 million for 2008 versus 2007 is principally from increased earnings resulting from an additional $53 million investment we made in Transco in December 2007.

Other income: These items include interest and dividend income on temporary investments, non-utility revenues relating to rental water heaters, and miscellaneous other income. The decrease of $0.7 million for 2009 versus 2008 resulted primarily from lower interest and dividend income. There were no significant variances for 2008 versus 2007.

Other Deductions: These items include supplemental retirement benefits and insurance, including changes in the cash surrender value of variable life insurance policies, non-utility expenses relating to rental water heaters, and miscellaneous other deductions. The decrease of $3.2 million for 2009 versus 2008 was related to changes in the cash surrender value of variable life insurance policies included in our Rabbi Trust. In 2009, there were market gains of $0.6 million versus market losses of $2.6 million in 2008. The increase of $2.3 million for 2008 versus 2007 resulted primarily from market losses on the cash surrender value of variable life insurance policies.

Income tax expense: 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. There was no significant variance for 2009 versus 2008. See Part II, Item 8, Note 16 - Income Taxes for the change in income expense for 2008 versus 2007.

CRC provided a $0.8 million favorable variance in 2009 versus 2008. This included the reversal of a $0.2 million valuation allowance that was established in 2008, and the recognition of a previously unrecognized tax position of $0.3 million.

Interest Expense Interest expense includes interest on long-term debt, dividends associated with preferred stock subject to mandatory redemption, interest on notes payable and the credit facilities, and carrying charges associated with regulatory liabilities. 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).

	2009 over/(under) 2008		2008 over/(under) 2007	
	Total Variance	**Percent**	Total Variance	Percent
Interest on long-term debt	**$1,361**	**13.9%**	$2,581	35.9%
Other interest	**(1,460)**	**-76.5%**	565	42.0%
Allowance for borrowed funds during construction	**13**	**10.9%**	(100)	*
Total interest expense	**($86)**	**-0.74%**	$3,046	35.7%

* variance exceeds 100 percent

Interest on long-term debt: The increase of $1.4 million for 2009 versus 2008 was largely due to the $60 million first mortgage bonds issued in May 2008. The increase of $2.6 million for 2008 versus 2007 was largely due to the $60 million first mortgage bonds issued in May 2008.

Other interest expense: The decrease of $1.5 million for 2009 versus 2008 was principally related to a bridge loan that was repaid in May 2008 from proceeds of a long-term debt issue, partially offset by lower regulatory carrying costs. The increase of $0.6 million for 2008 versus 2007 was principally related to a bridge loan that was repaid in May 2008 from proceeds of a long-term debt issue, partially offset by lower regulatory carrying costs.

POWER SUPPLY MATTERS

Power Supply Management Our power supply portfolio includes a mix of baseload 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 maintain a balance between our power supplies and load obligations.

Our power supply management aims to minimize costs consistent with conservative levels of risk to our liquidity. Risk mitigation strategies are built around minimizing both forward price risks and operational risks while strictly limiting potential collateral exposure to our liquid assets. Other risks are mitigated by the power and transmission cost recovery process contained in the PCAM (see Retail Rates and Alternative Regulation). We also mitigate cost risks through limited wholesale transactions that hedge market price risk, as discussed below. In addition, we have insured against major outage cost exposure if the Vermont Yankee plant experiences unplanned outages and is unable to deliver energy under the current PPA with Entergy-Vermont Yankee. 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, in which we participate, that are administered by ISO-New England.

Our current power forecast suggests we have excess supply through 2011. We attempt to sell much of this excess energy in the forward market at fixed prices in order to reduce market price volatility and revenue volatility while remaining strictly within potential collateral exposure limits. During 2008, we entered into several forward sale contracts to hedge revenues for the majority of our forecasted excess power for 2009. In October 2009, we executed a forward sale for calendar year 2010. We also executed a forward purchase for delivery during the Vermont Yankee refueling outage that is scheduled for the spring of 2010. We expect that our attainment of an investment-grade credit rating will result in an expansion of the number of counterparties that are willing to transact with us. Going forward, we expect to continue our practice of constraining the net transaction volumes with individual counterparties to mitigate potential collateral exposures during stressed market conditions.

Sources of Energy We have among the cleanest power supplies in the country, with a very low reliance on fossil fuels and a high reliance on renewable energy. A breakdown of energy sources during the past three years follows.

	2009	2008	2007
Nuclear	**55%**	50%	48%
Hydro	**38%**	39%	39%
Oil and wood	**4%**	5%	6%
Other	**3%**	6%	7%
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 through the PPA between Entergy-Vermont Yankee and VYNPC. VYNPC's entitlement to plant output is approximately 83 percent and our share of plant output is approximately 29 percent; our nominal entitlement is approximately 180 MW. We have one secondary purchaser that receives less than 0.5 percent of our entitlement.

Entergy-Vermont Yankee 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. A scheduled refueling outage was completed in November 2008 and the next outage is scheduled for the spring of 2010. Our total VYNPC purchases were $64 million in 2009, $57.7 million in 2008 and $55.8 million in 2007.

Prices under the PPA increase $1 per megawatt-hour each calendar year, from $43 in 2010 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. Estimated annual purchases are expected to be $61 million for 2010, $63 million for 2011 and $16 million for 2012 until the contract expiration in March. 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.

We purchase replacement energy as needed when the Vermont Yankee plant is not operating or is operating at reduced levels. We typically acquire most of this replacement energy through forward purchase contracts and account for those contracts as derivatives.

In July 2008, the Vermont Yankee plant reduced production levels (also referred to as a "derate") for almost 12 days, reaching a low of approximately 17 to 20 percent capacity during some of that time. The derate resulted from issues related to the plant's cooling towers. The incremental costs of the replacement power that we purchased during that time amounted to approximately $1.1 million. We also lost approximately $1.1 million in resale sales revenue during that time. We were able to apply approximately $0.1 million as a reduction in purchased power expense from a regulatory liability established for the difference in the premium we paid for Vermont Yankee forced outage insurance and amounts collected in retail rates.

In the third quarter of 2007, the Vermont Yankee plant experienced a derate after the collapse of a cooling tower at the plant, and a two-day unplanned outage resulting from a valve failure. We purchased replacement energy adequate to meet most of our hourly load obligations during that period. The derate and unplanned outage increased our net power costs by about $1.3 million in the third quarter of 2007 through increased purchased power expense and decreased operating revenues due to reduced resale sales. We were also able to apply $0.3 million as reduction in purchased power expense from the regulatory liability.

We are considering whether to seek recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the PPA based upon the results of certain reports, including an NRC inspection, in which the inspection team found that Entergy-Vermont Yankee, among other things, did not have sufficient design documentation available to help it prevent problems with the cooling towers. The NRC released its findings on October 14, 2008. In considering whether to seek recovery, we are also reviewing the 2007 and 2008 root cause analysis reports by Entergy and a December 22, 2008 reliability assessment provided by the Nuclear Safety Associates to the State of Vermont. We cannot predict the outcome of this matter at this time.

We have a forced outage insurance policy to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The current policy covers March 22, 2009 through March 21, 2010. This outage insurance does not apply to derates or acts of terrorism. The coverage applies to unplanned outages of up to 90 consecutive calendar days per outage event, and provides for payment of the difference between the hourly spot market price and $42/mWh. The aggregate maximum coverage is $9 million with a $1.2 million deductible. In October 2009, we purchased coverage for the period March 22, 2010 through March 21, 2011. The new policy has substantially the same coverage terms as our current policy.

The PPA between Entergy-Vermont Yankee and VYNPC contains a formula for determining the VYNPC power entitlement following an uprate in 2006 that increased the plant's operating capacity by approximately 20 percent. VYNPC and Entergy-Vermont Yankee 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, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.5 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 such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results if the costs are recovered in a timely fashion.

Hydro-Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. 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, altering 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. The average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015.

The annual load factor is 75 percent for the remainder of the VJO Power Contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described below.

There are two sellback contracts with provisions that apply to existing and future VJO Power Contract purchases. Two other sellback contracts, also negotiated in the early phase of the VJO Power Contract, have expired. The first sellback contract resulted in the sellback of 25 MW of capacity and associated energy through April 30, 2012, which has no net impact currently since an identical 25 MW purchase was made in conjunction with the sellback. We have a 23 MW share of the 25 MW sellback. However, since the sellback ends six months before the corresponding purchase ends, the first sellback will result in a 23 MW increase in our capacity and energy purchases for the period from May 1, 2012 through October 1, 2012.

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Quebec that are still available. The first option 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. To date, Hydro-Quebec has not 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.

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, 2009, our obligation is about 47 percent of the total VJO Power Contract through 2016, and represents approximately $352.1 million, on a nominal basis.

In accordance with FASB's guidance for guarantees, 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 an additional $412.7 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2010 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, and could 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.

Independent Power Producers: We receive power from several Independent Power Producers ("IPPs"). These plants use water or biomass as fuel and, with our own units, Hydro-Quebec and Vermont Yankee, are factors in our ability to provide energy with relatively low carbon emissions. Most of the IPP power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Our total purchases from IPPs were $22.6 million in 2009, $26.4 million in 2008 and $22.8 million in 2007. Estimated annual purchases are expected to range from $9.9 million to $21.5 million for the years 2010 through 2014. Costs will begin to drop when a major contract obligation ends in 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 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; two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW; and one diesel peaking unit with a nameplate capacity of 2.4 MW, which is currently deactivated. In 2009, we upgraded our Arnold Falls unit in St. Johnsbury, VT, investing approximately $1.4 million in the facility. The improvements are expected to ensure the plant's long-term viability and increase production by about 10 percent.

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 is 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 August 2008, the NRC approved a request by DNC to increase the Millstone Unit #3 plant's generating capacity by approximately 7 percent. We are obligated to pay our share of the related costs based on our ownership share described above. The uprate was completed during the scheduled refueling outage that concluded in November 2008 and our share of plant output increased by 1.4 MW.

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 the 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 commenced in May 2008. On October 15, 2008, the United States Court of Federal Claims issued a favorable decision in the case, including damages specific to Millstone Unit #3. The DOE appealed the court's decision in December 2008. On February 20, 2009, the government filed a motion seeking an indefinite stay of the briefing schedule. On March 18, 2009, the Court granted the government's request to stay the appeal. On November 19, 2009, DNC filed a motion to lift the stay. The DOE opposed this motion and also asked the Court to grant it an additional 45 days to file its initial brief in the appeal should the Court lift the stay. Once the stay is lifted, briefing on the appeal will take place. 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 and 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 costs related to our power generation, purchase and delivery of energy to customers and reflect energy prices, customer demand, and the demands on transmission and generation resources.

ISO-New England has a 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 and the amount of qualifying capacity in the pool. Based on specified rates through May 2010, we expect net FCM charges of about $2.5 million in 2010.

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.

Future Power Supply Long-term contracts with Vermont Yankee and Hydro-Quebec provide about two-thirds of our current power supply. There is a risk that future sources available to replace these contracts may be less reliable and impose significantly higher prices than current portfolio resources. These contracts are described in more detail in Part II, Item 8, Note 17 - Commitments and Contingencies.

Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that we could lose this resource if the plant shuts down for any reason before that date. An early shutdown could cause our customers to lose economic benefit of an energy volume of 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 now available forward market prices as of December 31, 2009, the incremental replacement cost of lost power is estimated to average $27.5 million in 2010. 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 of such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results if the costs are recovered in retail rates in a timely fashion.

Entergy-Vermont Yankee has submitted a renewal application with the NRC and an application for a Certificate of Public Good ("CPG") with the PSB for a 20-year extension of the Vermont Yankee plant operating license. Entergy-Vermont Yankee also needs approval from the PSB and Vermont Legislature to continue to operate beyond 2012. Significant hurdles may prevent its relicensing. Potential operating, transparency and communication issues related to the plant and its operations have raised serious concerns among regulators and members of the Vermont Legislature, including some who have called for its temporary or permanent shutdown. An intervenor in the CPG case has requested that the PSB order a shutdown of the Vermont Yankee plant pending resolution of current tritium leaks at the site. The PSB has opened a new docket to consider that request. We are unable to predict the outcome of this matter.

On February 24, 2010, in a non-binding vote, the Vermont Senate voted against allowing the PSB to consider granting the Vermont Yankee plant another 20-year operating license after 2012. A new Vermont legislature will be elected in the fall of 2010 and could vote differently. We are unable to predict the outcome of this matter.

At this time, Entergy-Vermont Yankee is attempting to overcome these concerns, but we have not held any formal negotiations on a new contract since these issues arose in January. We rejected Entergy-Vermont Yankee's current proposal, but both parties are prepared to resume negotiations for a purchased power contract when the issues that have emerged are resolved. We cannot predict the outcome at this time.

Under the terms of sale of the plant in 2002, Entergy-Vermont Yankee also agreed to a Revenue Sharing Agreement ("RSA") for the period 2012 through 2022. The RSA will effectively yield revenue to us on a certain MW portion of the plant's actual output whenever the average annual unit revenue exceeds a "strike price" that is established by formula beginning at $61/ mWh in 2012. Should the plant be relicensed and operate through March of 2022, the effect of the RSA will be to provide a price cap-like effect (at the level of the strike price) on the net cost of a purchase of an equal quantity of power made at market prices. Protection from upward price volatility above the level of the RSA represents a significant economic value to our consumers.

Contract deliveries from Hydro-Quebec will decline by approximately 19 percent after 2012, by approximately 84 percent after 2015 and will cease in 2016. The first reduction will serve to reduce the amount of the Company's power supply expected through October 2015. Hydro-Quebec is engaged in the addition of approximately 4,000 MW of hydroelectric capacity in Quebec largely targeted for export in part via increased transmission capacity into the New England market area. We are negotiating with Hydro-Quebec for future purchases that could supplement or replace current purchases from them.

On March 11, 2010, we signed a memorandum of understanding ("MOU") with Green Mountain Power and Hydro-Quebec ("Parties") that sets the stage for a new power supply contract. Under the terms of the MOU, Vermont utilities will be eligible to purchase up to 225 megawatts starting in November 2012 and ending in 2038. We will seek to purchase volumes similar to what we currently purchase from Hydro-Quebec. There is a price-smoothing mechanism that will shield customers from volatile market price spikes over the life of the contract.

The MOU commits the parties to negotiate in good faith a power purchase agreement based on a non-binding term sheet. The parties intend to negotiate the material terms of the power purchase agreement no later than June 30, 2010, to allow the parties to obtain all necessary internal organizational approvals and execute the agreement no later than July 31, 2010. The final agreement will be subject to PSB approval. Should the parties fail to execute an agreement for any reason prior to July 31, 2010, the MOU and the obligations of the parties to negotiate a final agreement will terminate.

Power Supply Request For Proposal ("RFP") In November 2008, together with Green Mountain Power ("GMP") and Vermont Electric Cooperative ("VEC"), we issued a request for power supply proposals ("RFP") for up to 100 MW to diversify our future power supplies and plan for the expiration of major contracts with Vermont Yankee and Hydro-Quebec. We also issued a second solicitation, together with GMP, at the same time for up to 150 MW, contingent on the outcome of the Vermont Yankee relicensing initiative ("Contingent RFP"). The two RFPs are the first in a series of staggered resource solicitations planned to be issued over the next several years as we build our power supply portfolio for the future and plan for the uncertainties around our largest resources. We are pleased with the initial success of these efforts, and optimistic about the results of future RFPs.

The first RFP sought up to 40 MW each for us and GMP, and 20 MW for VEC. We invited NEPOOL participants and a wide range of power suppliers and developers to participate in both RFPs. Bidders responded from across the northeast and Canada with an aggregate proposal of over 1,800 MW of diverse supply options. Bidders included power marketers, energy developers, existing and to-be-built power plant owners and financial institutions. Hydro-Quebec and Entergy-Vermont Yankee were ineligible to participate in the RFPs because of the ongoing negotiations with the Vermont utilities.

Joint RFP responses were received in January 2009 and final proposals were received on February 27, 2009. We initially determined that six of the proposals would provide the best value under the portfolio scoring approach we submitted to the PSB as part of our Integrated Resource Planning proceedings. The evaluation methodology included, as a threshold, an evaluation of credit or collateral terms. All bidders have been notified of our determinations, and negotiations with the successful bidders have been completed or are in progress. Two of the finalists are existing renewable power plants while another is in the final stages of permitting.

On March 23, 2009, we executed a contract for the purchase of 15 MW of firm power to be delivered all hours during calendar years 2013-2015. On December 8, 2009, we executed another agreement to purchase 5 MW of the output of an existing hydro electric plant for 5 years beginning in 2012. On December 16, 2009, we executed a 20-year agreement to begin in 2012, contingent on PSB approval, for approximately 30 percent of the output from a new 99 MW wind project under development in New Hampshire. These contracts have been announced publicly, and we received positive initial feedback from legislators, customers and other key constituencies.

Of the remaining initial awards, two have been withdrawn and it is unknown at this time whether the single remaining award will result in an executed transaction.

Best and final proposals were received from Contingent RFP participants on May 1, 2009. We expect to continue working with these parties at least until the uncertainties related to the Vermont Yankee plant's relicensing and the new contract negotiations are resolved. This process could remain unresolved until mid-2010.

At this time, we are unable to predict the impact on our financial statements and cash flows resulting from these awards and signed contracts associated with these RFPs.

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, 2009, 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 that, 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, 2009, the total remaining approximate cost for decommissioning and other costs of each plant is as follows: $47.9 million for Maine Yankee, $274.1 million for Connecticut Yankee and $58.8 million for Yankee Atomic. Our share of the remaining obligations amounts to $1 million for Maine Yankee, $5.5 million for Connecticut Yankee and $2.1 million for Yankee Atomic. These estimates may be revised from time to time based on information available regarding future costs.

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 ("GTCC") waste from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel or GTCC waste has been collected by the DOE, and each company's spent fuel is stored at its own site. 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 was collected from our retail customers.

In 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. In December 2006, the DOE filed a notice of appeal of the court's decision and all three companies filed notices of cross appeals. In August 2008, the United States Court of Appeals for the Federal Circuit reversed the award of damages and remanded the cases back to the trial court. The remand directed the trial court to apply the acceptance rate in 1987 annual capacity reports when determining damages.

On March 6, 2009, the three companies submitted their revised statement of claimed damages for the case on remand. Maine Yankee claimed $81.7 million through 2002, and Connecticut Yankee claimed $39.7 million and Yankee Atomic claimed $53.9 million in damages through 2001. Our share of the claimed damages is based on our ownership percentages described above.

The trial phase of the remanded case occurred in August 2009. Post-trial briefing was completed in early November 2009, and final arguments were heard on December 10, 2009.

The Court of Federal Claims' original decision, if maintained on remand, established 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 did not resolve the question regarding damages in subsequent years, the decision did support future claims for the remaining spent fuel storage installation construction costs.

In December 2007, Maine Yankee, Connecticut Yankee and Yankee Atomic filed additional claims against the DOE for unspecified damages incurred for periods subsequent to the original case discussed above. On July 1, 2009, in a notification to the DOE, Maine Yankee, Connecticut Yankee and Yankee Atomic filed their claimed costs for damages. Maine Yankee claimed $43 million since January 1, 2003 and Connecticut Yankee and Yankee Atomic claimed $135.4 million and $86.1 million, respectively, since January 1, 2002. For all three companies, the damages were claimed through December 31, 2008.

Due to the complexity of these issues and the potential for further appeals, the three companies cannot predict the timing of the final determinations or the amount of damages that will actually be received. Each of the companies' respective FERC settlements requires that damage payments, net of taxes and further spent fuel trust funding, if any, be credited to wholesale ratepayers including us. We expect that our share of these awards, if any, would be credited to our retail customers.

TRANSMISSION MATTERS

As a load-serving entity in Vermont, we are required to share the costs of facilities used to transmit power to our system, including the region's Pool Transmission Facility ("PTF") network, the state's non-PTF network and facilities that we utilize that are owned by individual utilities and generators. These are all referred to as Transmission by Others costs ("TbyO"). Our greatest TbyO cost is for our share of the region's high-voltage PTF transmission system through monthly payments made under the NEPOOL Open Access Transmission Tariff ("NOATT"). Our allocation of NOATT costs, based on our percentage of monthly NEPOOL network load, is a small fraction of the total, normally between 1.6 and 2 percent, depending on the season. While this regional cost-sharing approach greatly reduces our costs related to qualifying Vermont transmission upgrades, we pay our share of the costs for new and existing NOATT-qualifying facilities located elsewhere in New England.

In recent years there have been a number of major transmission projects in Vermont undertaken by Transco, some of which are already in service. The majority of the costs of these projects are PTF and have been approved by NEPOOL for NOATT cost-sharing treatment. However, certain Vermont transmission facilities do not qualify for such cost sharing. Our share of costs of these local facilities is determined by the classification of each project; some are charged directly to specific utilities and some are shared by all Vermont utilities based on a load ratio share formula.

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, Vt., which we refer to as the Southern Loop. It serves about 25 percent of our load. We initiated a public engagement 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. This project was approved by the PSB in April 2008. Work commenced in June 2008 and was completed in February 2009. The condensers are rotating machines similar to motors used to provide reactive support on the electric power transmission systems without burning fuel. The condensers have improved the reliability in the Stratton/Manchester area of the Southern Loop. Transco also worked 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. The plan also included a new substation in Vernon and an expansion of the Coolidge Substation. These components are collectively known as the "Coolidge Connector." To address local reliability problems on our system, on February 12, 2009 the PSB also approved construction of a new substation in Newfane and a 345 kV loop between the new substation and the 345 kV Vernon-to-Cavendish line. The effort to involve the public in a meaningful dialogue about these issues has been hailed as a vast improvement over previous project-review processes. We believe this new way of conducting business led to better solutions, lower costs, and improved community relations. In fact, a statewide transmission planning committee was created in the wake of the Southern Loop outreach effort, patterned in many respects after it.

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 the PTF service on a non-discriminatory basis throughout New England via the NOATT.

Under the RTO, the Highgate Converter and related facilities owned by a number of Vermont utilities, including us, and Transco are classified as the Highgate Transmission Facility with RNS reimbursement treatment. Our net cost for the Highgate facilities is based on our NEPOOL network load share (about 2 percent) rather than our 48 percent ownership share of the facilities. Our share of reimbursements is about $2 million a year.

RECENT ENERGY POLICY INITIATIVES

Climate Change Legislation Vermont law requires the state to participate in the Regional Greenhouse Gas Initiative ("RGGI"). RGGI is a mandatory, market-based program with a goal of reducing greenhouse gas emissions in each state. The program is designed to cut CO_2 emissions from the power sector by 10 percent by 2018 for 10 northeastern and Middle Atlantic states. To reach this goal, states sell emission allowances through auctions and invest the proceeds in programs, such as energy efficiency, renewable energy and other clean energy technologies, for the benefit of consumers.

The PSB issued an order in July 2008 to implement the auction provisions of the RGGI program. The state is using the proceeds and other funding sources to fund energy efficiency related to heating fuels.

Over the past several years, the U.S. Congress has also considered bills that would regulate domestic greenhouse gas emissions. Considerable opposition to such legislation has mounted in recent months, and what appeared to be strong momentum toward passage has been slowed considerably. Such legislation remains a priority, but its fate remains uncertain.

We will continue to monitor state and federal legislative developments to evaluate whether, and the extent to which, any resulting statutes or rules may affect our business, including the ability of our out-of-state power suppliers to meet their obligations.

We cannot predict the effects of any such legislation at this time. We anticipate that compliance with greenhouse gas emission limitations for all suppliers may entail replacement of existing equipment, installation of additional pollution control equipment, purchase of allowances, curtailment of certain operations or other actions. Capital expenditures or operating costs resulting from greenhouse gas emission legislation or regulations could be material, and could significantly increase the wholesale cost of power.

Smart Metering Development In 2008, the Vermont Legislature enacted a law that, among other things, encouraged the development of "smart metering" technology. In response, the PSB opened an investigation into smart metering and rate design. Under the statute, after investigation, in utility territories where the PSB concludes it appropriate and cost-effective, the PSB shall require each Vermont utility to file plans for investment and deployment of appropriate technologies and plans and strategies for implementing advanced pricing with a goal of ensuring that all ratepayer classes have an opportunity to receive and participate effectively in advanced time-of-use pricing plans.

The alternative regulation plan approved by the PSB required us to file a plan to implement advanced metering infrastructure ("AMI") within our service territory. We had already begun extensive planning for that effort. In late 2008, a Memorandum of Understanding ("MOU") was reached between the Vermont electric utilities and the Department of Public Service on the standards and requirements associated with AMI deployments in Vermont. This MOU was approved by the PSB and we are now working to reach an MOU on the details of our own AMI plan, called CVPS SmartPower™, before we submit the plan to the PSB for approval. We are also working with the Vermont Telecommunications Authority, VELCO and other stakeholders to build a communications infrastructure that will support AMI and help advance broadband and wireless communications services in Vermont.

American Recovery and Reinvestment Act of 2009 In February 2009, the American Recovery and Reinvestment Act of 2009 ("ARRA") was enacted into law. ARRA contains various provisions related to the electric industry intended to stimulate the economy, including incentives for increased capital investment by businesses and incentives to promote renewable energy. These provisions include, but are not limited to, improving energy efficiency and reliability, electricity delivery (including so-called smart grid technology), energy research and development, and demand response management. We evaluated the provisions of ARRA and, in cooperation with other utilities and Vermont state officials, filed an application on August 6, 2009 for financial assistance pursuant to the DOE Office of Electricity Delivery and Energy Reliability, Smart Grid Investment Grant Program.

On October 27, 2009, the DOE announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer enhancements, and grid automation. As a sub-awardee on Vermont's Smart Grid Stimulus application, we expect to receive a grant of over $31 million to support the CVPS SmartPower™ project. We are actively working with the other Vermont utilities and the DOE to complete final negotiations, and anticipate that these negotiations will be complete by April 2010. We are not required to invest in the capital obligations of the CVPS SmartPower™ project unless or until we complete final award negotiations with the DOE.

Renewable Energy Legislation In May 2009, the Vermont Legislature passed legislation designed to encourage the rapid deployment of small-scale renewable energy projects in Vermont. While Vermont businesses and electric utilities raised concerns about the bill and its potential impact on customer rates, the bill passed and the governor allowed it to become a law without his signature. The bill set above-market rates for small-scale solar, wind, hydro and methane energy production intended to encourage development of those projects.

The legislation required the PSB to review the rates set in the law, and to maintain the rates at levels high enough to encourage the development of up to 50 MW of new small-scale renewable projects. During the fall of 2009, the PSB conducted preliminary analysis, and ultimately set rates under the so-called SPEED program at 24 cents per kWh for solar, 21.48 cents per kWh for micro wind projects (100 kW or less); 11.82 cents per kWh for small wind projects (101 kW to 2.2 MW); 14.11 cents per kWh for farm-methane projects; 12.5 cents per kWh for biomass projects; 12.26 cents per kWh for small hydro projects; and 9 cents per kWh for landfill methane projects.

Though state law has historically mandated least-cost energy planning, this law largely precludes consideration of the rate impacts on customers, and requires the PSB to set the rates at levels that cover all development costs and a prescribed return on equity for the project owners. A state agent will be required to purchase the energy from these units, and allocate it on a pro-rata basis to all Vermont utilities, including us. Our allocation will be about 40 percent of the total.

On October 19, 2009, the PSB received 238 applications for projects and subsequently, on October 22, conducted a lottery to reduce the number of applications to within the 50-MW statutory limit for total capacity. It is possible that the legislature will raise the capacity limit on these projects due to the significant number of unsuccessful applications, which would increase the amount of above-market energy all Vermont utilities, including the company, would be required to purchase. There is also a proposal in the legislature to pay the higher rates to some farm producers who use methane to create electricity but have contracts that currently pay at levels below the new rates set by the PSB.

The Vermont Legislature is also considering a variety of bills dealing with utility interconnection issues, taxation of renewable projects, solar power on farms and the state's solar tax credit. We cannot predict the outcome of any of these matters at this time.

RECENT ACCOUNTING PRONOUNCEMENTS

In November 2008, the SEC issued a proposed roadmap for the potential use of International Financial Reporting Standards ("IFRS") in the U.S. IFRS is a set of accounting standards developed by the International Accounting Standards Board ("IASB"), with a mission to develop a single set of global financial reporting standards for general purpose financial statements. The roadmap indicates that the SEC will reconvene in 2011 to evaluate progress towards certain identified milestones and decide whether a mandatory IFRS conversion should be required for all U.S. issuers beginning with large accelerated filers in 2014. On February 24, 2010, the SEC issued a statement laying out its position regarding global accounting standards. Among other things, the SEC stated that it has directed its staff to execute a work plan, which will include consideration of IFRS as it exists today and after the completion of various "convergence" projects currently underway between U.S. and international accounting standards-setters. By 2011, assuming completion of the FASB and IASB convergence projects, and the SEC staff's work plan, the SEC will decide whether to incorporate IFRS into the U.S. financial reporting system. If the SEC determines in 2011 to move forward with IFRS, the first time that U.S. companies would report under such a system would be no earlier than 2015.

In December 2008, the IASB added to its agenda a project on rate-regulated activities and in July 2009, the IASB issued an exposure draft on rate-regulated activities for comment and to determine whether entities with such activities could or should recognize an asset or liability as a result of rate regulation imposed by regulatory bodies or governments. We currently recognize regulatory assets and liabilities under FASB's guidance for regulated operations as described above, which is not currently provided for under IFRS. We are evaluating the potential impact that the application of IFRS may have on our financial statements, and we are unable to predict the outcome of this matter at this time.

Also, see Part II, Item 8, 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

The matters discussed in this item may contain forward-looking statements as described in our "Cautionary Statement Regarding Forward-Looking Information" section preceding Part I, Item 1, Business of this Form 10-K. Also see Part I, Item 1A, Risk Factors.

We consider our most significant market-related risks to be associated with wholesale power markets, equity markets and interest rates. Although 2008 was a challenging year in the financial markets with record low market returns and extraordinary volatility, the markets began to stabilize and trend toward more normal performance in the second half of 2009. Further decreases in the values of the assets in our pension, postretirement medical and nuclear decommissioning trust funds could increase our future cash outflows related to trust fund contributions. 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 amount to approximately 90 percent of our total energy (mWh) purchases. The contracts are described in more detail in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters and Part II, Item 8, Note 17 - Commitments and Contingencies. Summarized information regarding power purchases under these contracts follows.

		2009		2008		2007	
	Expires	**mWh**	**$/mWh**	mWh	$/mWh	mWh	$/mWh
Hydro-Quebec (a)	2016	**919,764**	**$68.60**	937,923	$67.88	998,411	$64.97
VYNPC (b)	2012	**1,551,925**	**$41.25**	1,417,144	$40.72	1,361,754	$40.96

(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 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. The Power Cost Adjustment Mechanism within our alternative regulation plan allows more timely recovery of our power costs in 2009, 2010 and 2011.

We account for some of our power contracts as derivatives under FASB's guidance for derivatives and hedging. These derivatives are described in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, 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 Energy Contracts	**Financial Transmission Rights**	**Hydro-Quebec Sellback #3**	**Total**
Total fair value at December 31, 2008	$12,753	$136	($4,069)	$8,820
Gains and losses (realized and unrealized)				
Included in earnings	23,226	(113)	0	23,113
Included in Regulatory and other assets/liabilities	(12,484)	0	3,920	(8,564)
Purchases, sales, issuances and net settlements	(23,226)	111		(23,115)
Total fair value at December 31, 2009	$269	$134	($149)	$254
Estimated fair value at December 31, 2009 for changes in projected market price:				
10 percent increase	($2,623)	$148	($985)	($3,460)
10 percent decrease	$3,182	$121	$0	$3,303

Pursuant to a PSB-approved Accounting Order, changes in fair value of all power-related derivatives are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the change in 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 associated with 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 benefit trust funds and the valuations of 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 with a goal to mitigate these market impacts. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, and Part II, Item 8, Note 15 - 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, 2009, the trust held debt securities in the amount of $1.2 million.

As of December 31, 2009, we had $10.8 million of Industrial Development Revenue bonds outstanding, which have an interest rate that floats monthly. The interest rate on the year-end borrowings under our $40 million credit facility floats daily. All other utility debt has a fixed rate. There are no interest rate locks or swap agreements in place.

The table below provides information about interest rates on our long-term debt. The expected variable rates are based on rates in effect at December 31, 2009 (dollars in millions).

	Expected Long-term Debt Maturity Date						
	2010	2011	2012	2013	2014	Thereafter	Total
Fixed Rate ($)	**$10.8**	$10.2	$9.8	$9.8	$9.8	$102.3	$152.7
Average Fixed Interest Rate (%)	**6.44%**	6.54%	6.64%	6.64%	6.64%	7.01%	
Variable Rate ($)	**$0.3**	$0.3	$0.1	$0.1	$0.0	$0.0	$0.8
Average Variable Rate (%)	**0.84%**	0.84%	0.75%	0.75%	0.75%	0.75%	

Equity Market Risk: As of December 31, 2009, our pension trust held marketable equity securities in the amount of $60.4 million, our postretirement medical trust funds held marketable equity securities in the amount of $9.2 million, our Millstone Unit #3 decommissioning trust held marketable equity securities of $3.8 million and our Rabbi Trust held variable life insurance policies with underlying marketable equity securities of $2.7 million. These equity investments were affected by the global decline in the equity market that began in 2008, but experienced positive performance in 2009. Also see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, and Note 15 - Pension and Postretirement Medical Benefits for additional information.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

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, 2009 and 2008, 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, 2009. 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 the 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 Electric Power Company, Inc. ("Velco"), the Company's investments in which are accounted for by use of the equity method. The Company's equity of $126,742,000 and $99,121,000 in Transco's and Velco's net assets as of December 31, 2009 and 2008, respectively, and of $17,124,000, $16,102,000 and $5,886,000 in Transco's and Velco's net income for each of the three years in the period ended December 31, 2009, are included in the accompanying consolidated financial statements. Those financial statements were audited by other auditors whose reports (which as to Velco included an explanatory paragraph concerning a change in accounting for non-controlling interests) 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 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 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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.

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, 2009, 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 12, 2010 expresses an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 12, 2010

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

	For the year ended December 31		
	2009	2008	2007
Operating Revenues	**$342,098**	$342,162	$329,107
Operating Expenses			
Purchased Power - affiliates	**65,329**	59,778	58,361
Purchased Power - other	**92,653**	105,673	102,361
Production	**11,374**	12,223	11,700
Transmission - affiliates	**8,002**	7,280	5,144
Transmission - other	**23,799**	18,851	16,524
Other operation	**59,160**	55,744	53,457
Maintenance	**24,212**	27,992	27,937
Depreciation	**16,921**	15,660	15,217
Taxes other than income	**16,727**	15,653	15,140
Income tax expense	**5,033**	4,878	5,291
Total Operating Expenses	**323,210**	323,732	311,132
Utility Operating Income	**18,888**	18,430	17,975
Other Income			
Equity in earnings of affiliates	**17,472**	16,264	6,430
Allowance for equity funds during construction	**161**	328	47
Other income	**2,935**	3,598	3,813
Other deductions	**(1,585)**	(4,805)	(2,481)
Income tax expense	**(5,640)**	(5,862)	(1,458)
Total Other Income	**13,343**	9,523	6,351
Interest Expense			
Interest on long-term debt	**11,139**	9,778	7,197
Other interest	**449**	1,909	1,344
Allowance for borrowed funds during construction	**(106)**	(119)	(19)
Total Interest Expense	**11,482**	11,568	8,522
Net Income	**20,749**	16,385	15,804
Dividends declared on preferred stock	**368**	368	368
Earnings available for common stock	**$20,381**	$16,017	$15,436
Per Common Share Data:			
Basic earnings per share	**$1.75**	$1.53	$1.52
Diluted earnings per share	**$1.74**	$1.52	$1.49
Average shares of common stock outstanding - basic	**11,660,170**	10,458,220	10,185,930
Average shares of common stock outstanding - diluted	**11,705,518**	10,536,131	10,350,191
Dividends declared per share of common stock	**$0.92**	$0.92	$0.92

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)

	2009	2008	2007
Net Income	**$20,749**	$16,385	$15,804
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 $2 in 2009, $1 in 2008 and $12 in 2007	**3**	2	19
Prior service cost, net of income taxes of $9 in 2009 and 2008 and 2007	**14**	13	13
Transition benefit obligation, net of income taxes of $0 in 2009, 2008 and 2007.	**0**	1	1
Portion reclassified to retained earnings due to change in the benefit measurement date:			
Prior service cost, net of income taxes of $0 in 2009, $2 in 2008 and $0 in 2007	**0**	4	0
Change in funded status of pension, postretirement medical and other benefit plans, net of income taxes of $2 in 2009, $89 in 2008 and $92 in 2007	**2**	130	133
Comprehensive income adjustments	**19**	150	166
Total comprehensive income	**$20,768**	$16,535	$15,970

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 by:	**2009**	2008	2007
OPERATING ACTIVITIES			
Net income	**$20,749**	$16,385	$15,804
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of affiliates	**(17,472)**	(16,264)	(6,430)
Distributions received from affiliates	**10,695**	10,694	4,894
Depreciation	**16,921**	15,660	15,217
Deferred income taxes and investment tax credits	**9,633**	16,723	2,726
Amortization of capital leases	**946**	900	873
Regulatory and other amortization, net	**(797)**	(4,698)	(5,097)
Non-cash employee benefit plan costs	**6,275**	5,641	6,794
Other non-cash expense and (income), net	**5,225**	6,058	3,979
Changes in assets and liabilities:			
Increase in accounts receivable and unbilled revenues	**(6,520)**	(2,454)	(366)
Increase (decrease) in accounts payable	**4,979**	(1,740)	(504)
Increase (decrease) in accounts payable - affiliates	**702**	(1,867)	1,183
Decrease in other current assets	**4,409**	1,456	614
(Increase) decrease in special deposits and restricted cash for power collateral	**(1,734)**	(3,580)	3,519
Employee benefit plan funding	**(7,122)**	(7,880)	(7,878)
Decrease in other current liabilities	**(4,986)**	(5,222)	(2,362)
Decrease (increase) in other long-term assets	**132**	(2,178)	40
Increase in other long-term liabilities and other	**7**	766	1,086
Net cash provided by operating activities	**42,042**	28,400	34,092
INVESTING ACTIVITIES			
Construction and plant expenditures	**(31,413)**	(36,835)	(23,663)
Investments in available-for-sale securities	**(3,761)**	(1,475)	(20,797)
Proceeds from sale of available-for-sale securities	**3,436**	1,201	20,670
Investment in affiliates (Transco)	**(20,843)**	(3,090)	(53,000)
Other investing activities	**(350)**	(299)	170
Net cash used for investing activities	**(52,931)**	(40,498)	(76,620)
FINANCING ACTIVITIES			
Net proceeds from the issuance of common stock	**1,655**	23,540	2,131
Retirement of preferred stock subject to mandatory redemption	**(1,000)**	(1,000)	(1,000)
Common and preferred dividends paid	**(11,088)**	(9,868)	(9,734)
Proceeds from issuance of first mortgage bonds	**0**	60,000	0
Repayment of revenue and first mortgage bonds	**(5,450)**	(3,000)	0
(Repayment of) proceeds from short-term bridge loan	**0**	(53,000)	53,000
Proceeds from revolving credit facilities and other short-term borrowings	**48,501**	12,700	45,600
Repayments under revolving credit facility and other short-term borrowings	**(25,190)**	(12,700)	(45,600)
Payments required for unremarketed bonds	**0**	(3,400)	0
Proceeds from remarketed bonds	**0**	3,400	0
Debt issuance and common stock offering costs	**(210)**	(1,054)	0
Other financing activities	**(982)**	(601)	(865)
Net cash provided by financing activities	**6,236**	15,017	43,532
Net (decrease) increase in cash and cash equivalents	**(4,653)**	2,919	1,004
Cash and cash equivalents at beginning of the period	**6,722**	3,803	2,799
Cash and cash equivalents at end of the period	**$2,069**	$6,722	$3,803

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, 2009	December 31, 2008
ASSETS		
Utility plant		
Utility plant, at original cost	**$593,211**	$554,506
Less accumulated depreciation	**254,858**	244,219
Utility plant, at original cost, net of accumulated depreciation	**338,353**	310,287
Property under capital leases, net	**5,302**	6,133
Construction work-in-progress	**10,235**	24,632
Nuclear fuel, net	**2,190**	1,475
Total utility plant, net	**356,080**	342,527
Investments and other assets		
Investments in affiliates	**129,733**	102,232
Non-utility property, less accumulated depreciation ($3,661 in 2009 and $3,657 in 2008)	**1,900**	1,786
Millstone decommissioning trust fund	**5,082**	4,203
Other	**6,542**	5,469
Total investments and other assets	**143,257**	113,690
Current assets		
Cash and cash equivalents	**2,069**	6,722
Restricted cash	**5,369**	3,636
Special deposits	**1,007**	1,006
Accounts receivable, less allowance for uncollectible accounts ($3,577 in 2009 and $2,184 in 2008)	**24,597**	23,176
Accounts receivable - affiliates	**40**	76
Unbilled revenues	**20,827**	18,546
Materials and supplies, at average cost	**6,219**	6,299
Prepayments	**14,055**	17,367
Deferred income taxes	**3,351**	
Power-related derivatives	**622**	12,758
Other current assets	**2,252**	1,269
Total current assets	**80,408**	90,855
Deferred charges and other assets		
Regulatory assets	**46,240**	63,474
Other deferred charges - regulatory	**1,544**	9,980
Other deferred charges and other assets	**4,623**	5,467
Power-related derivatives	**0**	133
Total deferred charges and other assets	**52,407**	79,054
TOTAL ASSETS	**$632,152**	$626,126

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, 2009	December 31, 2008
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 13,835,968 issued and 11,706,895 outstanding at December 31, 2009 and 13,750,717 issued and 11,574,825 outstanding at December 31, 2008	**$83,016**	$82,504
Other paid-in capital	**72,179**	71,489
Accumulated other comprehensive loss	**(209)**	(228)
Treasury stock, at cost, 2,129,073 shares at December 31, 2009 and 2,175,892 shares at December 31, 2008	**(48,436)**	(49,501)
Retained earnings	**124,873**	115,215
Total common stock equity	**231,423**	219,479
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Preferred stock subject to mandatory redemption	**0**	1,000
Long-term debt	**201,611**	167,500
Capital lease obligations	**4,313**	5,173
Total capitalization	**445,401**	401,206
Current liabilities		
Current portion of preferred stock subject to mandatory redemption	**1,000**	1,000
Current portion of long-term debt	**0**	5,450
Accounts payable	**9,016**	3,549
Accounts payable – affiliates	**12,040**	11,338
Notes payable	**0**	10,800
Nuclear decommissioning costs	**1,443**	1,431
Power-related derivatives	**219**	2
Other current liabilities	**26,450**	33,645
Total current liabilities	**50,168**	67,215
Deferred credits and other liabilities		
Deferred income taxes	**59,215**	45,314
Deferred investment tax credits	**2,642**	2,962
Nuclear decommissioning costs	**7,055**	8,618
Asset retirement obligations	**3,247**	3,302
Accrued pension and benefit obligations	**38,056**	51,211
Power-related derivatives	**149**	4,069
Other deferred credits - regulatory	**3,888**	17,696
Other deferred credits and other liabilities	**22,331**	24,533
Total deferred credits and other liabilities	**136,583**	157,705
Commitments and contingencies – See Note 17		
TOTAL CAPITALIZATION AND LIABILITIES	**$632,152**	$626,126

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
(in thousands, except share data)

	Common Stock		Treasury Stock			Accumulated		
	Shares Issued	Amount	Shares	Amount	Other Paid-in Capital	Other Comprehensive Loss	Retained Earnings	Total
Balance, December 31, 2006	12,382,801	$74,297	(2,249,975)	($51,186)	$54,225	($544)	$102,560	$179,352
Cumulative effect of adoption of FIN 48							120	120
Adjusted balance at January 1, 2007	12,382,801	$74,297	(2,249,975)	($51,186)	$54,225	($544)	$102,680	$179,472
Net Income							15,804	15,804
Other comprehensive income						166		166
Dividend reinvestment plan	9,721	58	19,847	452	475			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)
Non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					17			17
Loss on reacquisition of capital stock					3		(3)	
Balance, December 31, 2007	12,474,687	$74,848	(2,230,128)	($50,734)	$56,324	($378)	$108,747	$188,807
Adjust to initially apply SFAS 158 measurement provision, net of tax						4	(46)	(42)
Net income							16,385	16,385
Other comprehensive income						146		146
Common stock issuance, net of issuance costs	1,190,000	7,140			13,760			20,900
Dividend reinvestment plan			54,236	1,233				1,233
Stock options exercised	67,050	402			882			1,284
Share-based compensation:								
Common & nonvested shares	3,891	23			65			88
Performance share plans	15,089	91			418			509
Dividends declared:								
Common - $0.92 per share							(9,500)	(9,500)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					17			17
Gain (loss) on capital stock					23		(3)	20
Balance, December 31, 2008	**13,750,717**	**$82,504**	**(2,175,892)**	**($49,501)**	**$71,489**	**($228)**	**$115,215**	**$219,479**
Net income							20,749	20,749
Other comprehensive income						19		19
Common stock issuance costs					(179)			(179)
Dividend reinvestment plan	19,468	117	46,819	1,065	255			1,437
Stock options exercised	36,160	217			284			501
Share-based compensation:								
Common & nonvested shares	4,530	27			58			85
Performance share plans	25,093	151			417			568
Dividends declared:								
Common - $0.92 per share							(10,720)	(10,720)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					16			16
Gain (loss) on capital stock					(161)		(3)	(164)
Balance, December 31, 2009	**13,835,968**	**83,016**	**(2,129,073)**	**(48,436)**	**72,179**	**(209)**	**124,873**	**$231,423**

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 the largest electric utility in Vermont. We engage principally in the purchase, production, transmission, distribution and sale of electricity. We serve approximately 159,000 customers in 163 of the towns and cities in Vermont. Our Vermont utility operation is our core business. We typically generate most of our revenues through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-New England, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue generated from these sales helps to mitigate our power supply costs.

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").

Basis of Presentation These audited financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission and in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). The accompanying consolidated financial statements contain all normal, recurring adjustments considered necessary to present fairly the financial position as of December 31, 2009, and the results of operations and cash flows for the 12-month periods ended December 31, 2009, 2008 and 2007. These consolidated financial statements should be read in conjunction with the accompanying notes. We consider events or transactions that occur after the balance sheet date, but before the financial statements are issued, to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure.

Financial Statement Presentation The focus of the Consolidated Statements of Income is on the regulatory treatment of revenues and expenses of the regulated utility 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 non-utility 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 wholly owned subsidiaries. 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 FASB's consolidation guidance for variable interest entities. See Part II, Item 8, Note 3 - Investments in Affiliates.

Variable Interest Entities The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities of that entity. Transco and VYNPC are variable interest entities; however, we are not the primary beneficiary of these entities based on our assessments of the expected losses and expected residual returns to be absorbed by other entities under the various tariff agreements. Our maximum exposure to loss is the amount of our equity investments in Transco and VYNPC. See Part II, Item 8, Note 3 - Investments in Affiliates.

Use of Estimates The preparation of financial statements in accordance with 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 required, we prepare our financial statements in accordance with FASB's guidance for regulated operations. The application of this guidance 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 the accounting for regulated operations, 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 the majority of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, we would reassess whether this accounting standard would continue to apply to our regulated operations. In the event we determine that we no longer meet the criteria for applying the accounting for regulated operations, the accounting impact would be a 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 accounting for regulated operations 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 the guidance for regulated operations and there is not a rate mechanism to recover these costs, the impact would, among other things, result in a charge to operations of $11.8 million pre-tax at December 31, 2009. See Part II, Item 8, 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 FASB's guidance for income tax accounting, 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.

We follow FASB's guidance and methodology for estimating and reporting amounts associated with uncertain tax positions, including interest and penalties, and we adopted the related guidance on January 1, 2007, as required. Upon adoption, 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):

	2009	2008	2007
Balance at January 1	**$1,662**	$1,870	$669
Reductions from lapse of the statute of limitations	**(556)**	(74)	(39)
Reductions due to the passage of time (depreciation)	**(119)**	(134)	0
Gross amount of increase as a result of current year tax positions	**0**	0	1,240
Balance at December 31	**$987**	$1,662	$1,870

There were no unrecognized tax benefits that would affect the effective tax rate if recognized at December 31, 2009 and $0.4 million at December 31, 2008 and 2007. During 2009, unrecognized tax benefits were reduced by $0.7 million, which due to the impact of deferred tax accounting, had a $0.4 million impact on the effective tax rate. During 2008, unrecognized tax benefits were reduced by $0.2 million, which due to the impact of deferred tax accounting, had a nominal impact on the effective tax rate.

We recognize interest related to unrecognized tax benefits as interest expense and penalties as other deductions. All previously accrued interest related to unrecognized tax benefits, which totaled $0.1 million, was reversed during the fourth quarter of 2009. The remaining unrecognized tax benefits relate to benefits requested but not received; therefore interest expense does not accrue. Accrued interest related to unrecognized tax benefits amounted to less than $0.1 million as of December 31, 2008 and 2007.

During 2007, we determined that we would file amended returns related to the 2003 - 2006 tax years and increased unrecognized tax benefits by an additional $1.2 million. Because of the impact of deferred tax accounting, the disallowance of this item would not affect the effective tax rate. The Internal Revenue Service ("IRS") completed its audit of the 2003, 2004 and 2005 tax years during 2008, resulting in nominal refunds due to us on the agreed portion of the audit. The IRS audit of the 2006 tax year was completed during 2009 with no proposed audit adjustments on the agreed portion of the audit. Our Casualty Loss refund claims for the 2003 through 2006 tax years were denied and are currently pending review at IRS Appeals. For federal tax purposes the 2003 tax year remains open to the IRS to exercise their right of offset for any amount awarded to us for the Casualty Loss claim for that year. The 2004 through 2006 tax years, although audited, and the 2007 and 2008 tax years remain open. For state tax purposes the 2004 through 2008 tax years remain open to examination by the states of New York, New Hampshire, Maine, Connecticut and Vermont.

It is reasonably possible that a decrease of $1 million in our unrecognized tax benefits will occur within 12 months of the reporting date because of an expected settlement of our 2003 through 2006 Casualty Loss claims with the IRS Appeals Office. While we anticipate the entire Casualty Loss claim for all years to be settled during 2010, the amount of the final IRS claim allowed remains uncertain and it is reasonably possible that the amount of our unrecognized tax benefits may increase or decrease by approximately $0.2 million as new information arises prior to final settlement. Due to the nature of deferred tax accounting, the recognition of the unrecognized tax benefits will have no impact on the effective tax rate.

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 2009, 2008 or 2007.

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):

	2009	2008
Wholly owned electric plant in service:		
Distribution	**$308,544**	$301,070
Hydro facilities	**48,634**	48,616
Transmission	**57,115**	45,044
General	**34,196**	34,788
Intangible plant	**5,512**	6,369
Other	**4,694**	4,693
Sub-total wholly owned electric plant in service	**458,695**	440,580
Jointly owned generation and transmission units	**115,397**	111,915
Completed construction	**19,076**	1,968
Held for future use	**43**	43
Utility plant, at original cost	**593,211**	554,506
Accumulated depreciation	**(254,858)**	(244,219)
Property under capital leases, net	**5,302**	6,133
Construction work-in-progress	**10,235**	24,632
Nuclear fuel, net	**2,190**	1,475
Total Utility Plant, net	**$356,080**	$342,527

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, 2009, Property under Capital Leases was comprised of $24.8 million of original cost less $19.5 million of accumulated amortization. At December 31, 2008, Property under Capital Leases was comprised of $24.6 million of original cost less $18.5 million of accumulated amortization. See Part II, Item 8, Note 17 - Commitments and Contingencies.

Depreciation We use the straight-line remaining life method of depreciation. The total composite depreciation rate was 2.85 percent of the cost of depreciable utility plant in 2009, 2.9 percent in 2008 and 2.89 percent in 2007.

Allowance for Funds Used During Construction Allowance for funds used 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 7.8 percent in 2009, and 8.6 percent in 2008 and 2007. 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):

	2009	2008
Asset retirement obligations at January 1	**$3,302**	$3,200
Revisions in estimated cash flows	**(233)**	(55)
Accretion	**192**	159
Liabilities settled during the period	**(14)**	(2)
Asset retirement obligations at December 31	**$3,247**	$3,302

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 $5.1 million in 2009 and $4.2 million in 2008, 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 $10.7 million in 2009 and $10 million in 2008 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 Part II, Item 8, Note 17 - Commitments and Contingencies.

Derivative Financial Instruments We account for certain power contracts as derivatives under the provisions of FASB's guidance for derivatives and hedging. This guidance requires that derivatives be recorded on the balance sheet at fair value. Our derivative financial instruments are related to managing our power supply resources to serve our customers, and are not for trading purposes. We have determined that these transactions do not qualify under the "normal" purchase and sale exception. Additionally, we have not elected hedge accounting for our power-related derivatives.

Based on a PSB-approved Accounting Order, we record the changes in fair value of all power-related derivative financial instruments as deferred charges or deferred credits on the balance sheet, depending on whether the change in 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 of the contracts. Realized gains and losses on sales are recorded as increases to or reductions of operating revenues, respectively. For purchase contracts, realized gains and losses are recorded as reductions of or additions to purchased power expense, respectively.

Our power-related derivatives include forward energy contracts, one long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice ("Hydro-Quebec Sellback #3") and financial transmission rights. All of our power-related derivatives are commodity contracts. For additional information about power-related derivatives, see Part II, Item 8, Note 5 - Fair Value.

Share-Based Compensation 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. See Part II, Item 8, Note 8 - Share-Based Compensation.

Pension and Benefits Our defined benefit pension plans and postretirement welfare benefit plans are accounted for in accordance with FASB's guidance for employee retirement benefits. We use the fair value method to value all asset classes included in our pension and postretirement medical benefit trust funds. See Part II, Item 8, Note 15 - Pension and Postretirement Medical Benefits for more information.

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

	AOCL After-tax
Balance at December 31, 2007	**($378)**
Pension and postretirement medical benefit costs, net	150
Balance at December 31, 2008	**($228)**
Pension and postretirement medical benefit costs, net	19
Balance at December 31, 2009	**($209)**

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 Part II, Item 8, Note 17 - Commitments and Contingencies.

Special Deposits Special deposits include mandatory sinking fund payments of $1 million in 2009 and 2008 for our preferred stock subject to mandatory redemption.

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):

	2009	2008	2007
Interest on temporary investments	**$61**	$257	$273
Non-utility revenue and non-operating rental income	**1,862**	1,901	1,842
Amortization of contributions in aid of construction - tax adder	**975**	991	951
Other interest and dividends	**16**	148	372
Gain on sale of non-utility property	**2**	7	105
Miscellaneous other income	**19**	294	270
Total	**$2,935**	$3,598	$3,813

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

	2009	2008	2007
Supplemental retirement benefits and insurance	**($249)**	$3,041	$785
Non-utility expenses	**1,320**	1,294	1,183
Miscellaneous other deductions	**513**	470	513
Total	**$1,585**	$4,805	$2,481

Prepayments: The components of Prepayments on the Consolidated Balance Sheets at December 31 follow (dollars in thousands):

	2009	2008
Taxes	**$12,443**	$14,924
Insurance	**1,055**	1,310
Miscellaneous	**557**	1,133
Total	**$14,055**	$17,367

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

	2009	2008
Deferred compensation plans and other	**$2,627**	$2,623
Accrued employee-related costs	**5,843**	4,946
Other taxes and Energy Efficiency Utility	**3,306**	5,882
Cash concentration account - outstanding checks	**1,917**	3,701
Obligation under capital leases	**975**	942
December 2008 storm accrual	**0**	3,491
Miscellaneous accruals	**11,782**	12,060
Total	**$26,450**	$33,645

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):

	2009	2008
Environmental reserve	**$890**	$973
Non-legal removal costs	**10,693**	9,954
Contribution in aid of construction - tax adder	**4,705**	5,210
Reserve for loss on power contract	**5,980**	7,175
Accrued income taxes and interest	**0**	683
Provision for rate refund	**4**	234
Other	**59**	304
Total	**$22,331**	$24,533

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 2009, 2008 and 2007, we declared and paid cash dividends of 92 cents per share of common stock.

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

	2009	2008	2007
Interest (net of amounts capitalized)	**$11,614**	$10,716	$8,073
Income taxes (net of refunds)	**$ (1,244)**	$3,142	$6,162

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, 2009, $0.5 million of construction and plant-related accruals was included in Accounts Payable, and $0.6 million was included in Other Current Liabilities. At December 31, 2008, less than $0.1 million of construction and plant-related accruals was included in Accounts Payable, and $2.1 million was included in Other Current Liabilities.

During 2009, we added $0.1 million to the Phase II capital lease, which increased the related asset and liability. Pursuant to agreements with Vermont regulatory authorities, we applied $0.3 million of other deferred credits – regulatory to reduce the cost of utility plant, in connection with a solar energy project and a hydro generating facility.

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.

Other non-cash expense and (income), net includes provision for uncollectible accounts, provision for rate refunds, the change in cash surrender value of whole life and variable life insurance policies held in our Rabbi Trust, share-based compensation, non-utility property depreciation and allowance for funds used during construction. Other investing activities include return of capital from investments in affiliates, non-utility capital expenditures, premiums paid on Rabbi Trust life insurance policies and death benefits received from such policies. Other financing activities include reductions in capital lease obligations, shares repurchased for mandatory tax withholdings and excess tax benefits relating to share-based compensation.

Recently Adopted Accounting Policies

Fair Value: In April 2009, FASB issued additional guidance related to debt and equity securities. This new guidance modifies the other-than-temporary impairment ("OTTI") model for investments in debt securities and enhances the disclosures for debt and equity securities. The primary change to the OTTI model for debt securities is the change in focus from an entity's intent and ability to hold a security until recovery. Instead, an OTTI is triggered if: 1) an entity has the intent to sell the security; 2) it is more likely than not that it will be required to sell the security before recovery; or 3) it does not expect to recover the entire unamortized cost of the security. The impairment loss is separated into two categories: the credit loss component, which is recorded in earnings, and the remainder of the impairment charge, which is recorded in other comprehensive income. This new guidance changes the recognition of the OTTI in the income statement if the entity does not expect to recover its entire unamortized cost. Although we adopted the provisions of the new guidance as of June 30, 2009, there was no material impact on our financial position, results of operations or cash flows. This is because our total impairment losses related to our Millstone Decommissioning trust funds are recorded to a regulatory liability on our Consolidated Balance Sheets and our prior period impairment amounts related to debt securities are not material. See Part II, Item 8, Note 6 - Investment Securities for further discussion of our investments in marketable securities.

In April 2009, FASB issued additional guidance to determine the fair value when the volume and level of activity for the asset or liability have significantly decreased and identifying transactions that are not orderly. It does not change the objective of fair value measurements when market activity declines. Fair value is 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 under current market conditions. The adoption of this guidance as of June 30, 2009 did not materially affect our financial position, results of operations or cash flows.

FASB Codification: In June 2009, the FASB issued guidance for generally accepted accounting principles ("Codification"). The Codification does not change U.S. GAAP, but combines all authoritative standards issued by organizations that are in levels A through D of the GAAP hierarchy, such as the FASB, AICPA and EITF, into a comprehensive, topically organized online database. We did not have any accounting impacts since this is an accumulation of existing guidance. We adopted the Codification for the period ending September 30, 2009.

Recent Accounting Pronouncements Not Yet Adopted

Variable Interest Entities: In June 2009, the FASB issued additional consolidation guidance related to variable interest entities and includes the addition of entities previously considered qualifying special-purpose entities. We have evaluated the additional guidance, and do not expect that it will have a material impact on our financial position, results of operations and cash flows. The guidance became effective for us on January 1, 2010.

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):

	2009	2008	2007
Numerator for basic and diluted EPS:			
Income from continuing operations	**\$20,749**	\$16,385	\$15,804
Dividends declared on preferred stock	**368**	368	368
Net income from continuing operations available for common stock	**\$20,381**	\$16,017	\$15,436
Denominators for basic and diluted EPS:			
Weighted-average basic shares of common stock outstanding	**11,660,170**	10,458,220	10,185,930
Dilutive effect of stock options	**20,646**	55,525	132,302
Dilutive effect of performance shares	**24,702**	22,386	31,959
Weighted-average diluted shares of common stock outstanding	**11,705,518**	10,536,131	10,350,191

Outstanding stock options totaling 153,017 for 2009 were excluded from the computation because the exercise prices were above the current average market price of the common shares. All outstanding stock options were included in the computation of diluted shares for 2008 and 2007 because the exercise prices were below the current average market price of common shares. Outstanding performance shares totaling 26,973 and 12,180 were excluded from the diluted EPS calculation as either the performance share measures were not met or there was an antidilutive impact as of December 31, 2009 and 2008, respectively. All performance shares were included in the diluted EPS calculation in 2007.

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	**2009**	2008	**2009**	2008	2007
Vermont Electric Power Company, Inc.:						
Common stock	47.05%	**$11,726**	$11,257			
Preferred stock	48.03%	**$268**	$267			
Subtotal		**11,994**	11,524	**$1,776**	$1,296	$1,404
Vermont Transco LLC (a)	33.35%	**114,748**	87,597	**15,348**	14,806	4,482
Vermont Yankee Nuclear Power Corporation	58.85%	**2,830**	2,763	**328**	144	431
Connecticut Yankee Atomic Power Company	2.00%	**65**	259	**13**	9	94
Maine Yankee Atomic Power Company	2.00%	**36**	34	**2**	6	8
Yankee Atomic Electric Company	3.50%	**60**	55	**5**	3	11
Total Investments in Affiliates		**$129,733**	$102,232	**$17,472**	$16,264	$6,430

(a) Ownership percentage was 33.02 percent at December 31, 2008.

Undistributed earnings of these affiliates, included in Retained Earnings on our Consolidated Balance Sheets, amounted to $15.2 million at December 31, 2009 and $8.5 million at December 31, 2008. Of these amounts, $14.5 million at December 31, 2009 and $8.2 million at December 31, 2008 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 $20.8 million in Transco in 2009 and $3.1 million in 2008. Our direct ownership interest was 33.35 percent at December 31, 2009 and 33.02 percent at December 31, 2008. 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, 2009, our total direct and indirect interest in Transco was 38.68 percent. It was 39.67 percent at December 31, 2008. Transco is a variable interest entity but we are not the primary beneficiary.

Cash dividends received from VELCO were $1.3 million in 2009, 2008 and 2007. Accounts payable to VELCO were $5.6 million at December 31, 2009 and December 31, 2008.

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

	2009	2008	2007
Operating revenues	**$93,596**	$75,660	$51,911
Operating income	**$51,903**	$40,088	$21,922
Income before non-controlling interest and income tax	**$42,214**	$35,688	$13,955
Less members' non-controlling interest in income	**36,202**	30,712	9,483
Less income tax	**2,338**	2,175	1,661
Net income	**$3,674**	$2,801	$2,811

	2009	2008
Current assets	**$76,257**	$34,687
Non-current assets	**649,187**	496,316
Total assets	**725,444**	531,003
Less:		
Current liabilities	**48,766**	63,725
Non-current liabilities	**355,951**	220,443
Members' non-controlling interest	**295,401**	222,409
Net assets	**$25,326**	$24,426

Transco's summarized financial information (included above in VELCO's summarized consolidated financial information) for 2009, 2008 and 2007 follows (dollars in thousands).

	2009	2008	2007
Operating revenues	**$93,085**	$75,200	$51,466
Operating income	**$51,903**	$40,088	$21,922
Net income	**$42,623**	$35,647	$13,904

	2009	2008
Current assets	**$77,386**	$33,791
Non-current assets	**639,796**	485,405
Total assets	**717,182**	519,196
Less:		
Current liabilities	**34,086**	49,179
Non-current liabilities	**347,627**	210,339
Mandatorily redeemable membership units	**10,000**	10,000
Net assets	**$325,469**	$249,678

Transmission services provided by Transco are billed to us under the VTA. All Vermont electric utilities are parties to the VTA. This agreement requires the Vermont utilities to pay their pro rata share of Transco's total costs, including interest and a fixed rate of return on equity, less the revenue collected under the ISO-New England Open Access Transmission Tariff and other agreements. 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. The parties reached a preliminary settlement in January 2008 and filed a definitive settlement agreement with the FERC in March 2008. The settlement agreement is supported by all parties, including us, and resolves all issues that were raised in the FERC proceedings. The FERC approved the settlement agreement on August 22, 2008, and related amendments to the Transco operating agreement necessary to implement the settlement were approved by the PSB.

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 of $8 million in 2009, $7.3 million in 2008 and $5.1 million in 2007 are included in Transmission - affiliates on our Consolidated Statements of Income. Accounts payable to Transco were $0.8 million at December 31, 2009 and $0.4 million at December 31, 2008. Cash dividends received were $9 million in 2009, $9.1 million in 2008 and $3.1 million in 2007.

VYNPC VYNPC sold its nuclear plant to Entergy Nuclear Vermont Yankee, LLC ("Entergy-Vermont Yankee") in July 2002. The sale agreement included a purchased power contract ("PPA") between VYNPC and Entergy-Vermont Yankee. Under the PPA, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates and, in turn, bills the PPA charges from Entergy-Vermont Yankee with certain residual costs of service through a FERC tariff to the VYNPC sponsors, including us. The residual costs of service include VYNPC's other operating expenses, including any expenses incurred in administering the PPA and the power contracts, and an allowed return on equity. Our entitlement to energy produced by the Vermont Yankee plant is about 29 percent. See Part II, Item 8, Note 17 - 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):

	2009	2008	2007
Operating revenues	**$183,411**	$166,104	$160,143
Operating income	**($2,991)**	($543)	$3,130
Net income	**$557**	$245	$733

	2009	2008
Current assets	**$23,926**	$28,102
Non-current assets	**146,957**	140,291
Total assets	**170,883**	168,393
Less:		
Current liabilities	**16,754**	16,009
Non-current liabilities	**149,320**	147,689
Net assets	**$4,809**	$4,695

VYNPC's revenues shown in the table above include sales to us of $64 million in 2009, $57.7 million in 2008 and $55.8 million in 2007. 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, 2009 and $5.3 million at December 31, 2008. Cash dividends received were $0.3 million in 2009, 0.2 million in 2008 and $0.4 million in 2007.

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 were to disallow recovery of any of these costs in their wholesale rates, there would be 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	$119.9	$47.9	$1.0
Connecticut Yankee	$146.4	$274.1	$5.5
Yankee Atomic	$101.7	$58.8	$2.1

The remaining obligations are the estimated remaining total costs to be incurred by the respective Yankee companies to operate the supporting organization and decommission the plant, including onsite spent fuel storage, in 2009 dollars for the period 2010 through 2023 for Maine Yankee and Connecticut Yankee and through 2022 for Yankee Atomic. Revenue requirements are the estimated future payments by the sponsors to fund estimated FERC-approved decommissioning and other costs (in nominal dollars) for 2010 through 2013 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 is 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 2008 FERC-approved settlement. Our share of decommissioning and other costs amounted to $0.1 million in 2009, $0.9 million in 2008 and $1.1 million in 2007. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income.

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. Our share of decommissioning and other costs amounted to $0.8 million in both 2009 and 2008 and $1 million in 2007. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income. Our share of dividends from Connecticut Yankee was $0.1 million in 2009. There were no dividends received in 2008. Our share of proceeds from Connecticut Yankee stock redemption in 2009 was $0.1 million. There were no proceeds from stock redemptions on 2008.

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 million for the period 2006-2010 and to increase its revenue requirements by $47 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 2009, 2008 and 2007. These amounts 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 ("GTCC") waste from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel or GTCC waste has been collected by the DOE, and each company's spent fuel is stored at its own site. 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 was collected from our retail customers.

In 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. In December 2006, the DOE filed a notice of appeal of the court's decision and all three companies filed notices of cross appeals. In August 2008, the United States Court of Appeals for the Federal Circuit reversed the award of damages and remanded the cases back to the trial court. The remand directed the trial court to apply the acceptance rate in 1987 annual capacity reports when determining damages.

On March 6, 2009, the three companies submitted their revised statement of claimed damages for the case on remand. Maine Yankee claimed $81.7 million through 2002, and Connecticut Yankee claimed $39.7 million and Yankee Atomic claimed $53.9 million in damages through 2001. Our share of the claimed damages is based on our ownership percentages described above.

The trial phase of the remanded case occurred in August 2009. Post-trial briefing was completed in early November 2009, and final arguments were heard on December 10, 2009.

The Court of Federal Claims' original decision, if maintained on remand, established 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 did not resolve the question regarding damages in subsequent years, the decision did support future claims for the remaining spent fuel storage installation construction costs.

In December 2007, Maine Yankee, Connecticut Yankee and Yankee Atomic filed additional claims against the DOE for unspecified damages incurred for periods subsequent to the original case discussed above. On July 1, 2009, in a notification to the DOE, Maine Yankee, Connecticut Yankee and Yankee Atomic filed their claimed costs for damages. Maine Yankee claimed $43 million since January 1, 2003 and Connecticut Yankee and Yankee Atomic claimed $135.4 million and $86.1 million, respectively since January 1, 2002. For all three companies the damages were claimed through December 31, 2008.

Due to the complexity of these issues and the potential for further appeals, the three companies cannot predict the timing of the final determinations or the amount of damages that will actually be received. Each of the companies' respective FERC settlements requires that damage payments, net of taxes and further spent fuel trust funding, if any, be credited to wholesale ratepayers including us. We expect that our share of these awards, if any, would be credited to our retail customers.

NOTE 4 - FINANCIAL INSTRUMENTS

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

	2009		2008	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Power contract derivative assets (includes current portion)	**$622**	**$622**	$12,891	$12,891
Power contract derivative liabilities (includes current portion)	**$368**	**$368**	$4,071	$4,071
Preferred stock subject to mandatory redemption (includes current portion)	**$1,000**	**$1,000**	$2,000	$2,003
Long-term debt:				
First mortgage bonds	**$167,500**	**$186,210**	$167,500	$159,172
Revenue bonds (included current portion in 2008)	**$10,800**	**$10,800**	$16,250	$16,183
Credit facility borrowings	**$23,311**	**$23,311**	-	-

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 2009, the fair values were unrealized losses of $0.4 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $0.6 million that were recorded as assets on the Consolidated Balance Sheet. In 2008, the fair values were unrealized losses of $4.1 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $12.9 million that were recorded as assets on the Consolidated Balance Sheet.

The fair values of our fixed rate securities are 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, special deposits, receivables and payables. The carrying values approximate fair value because of the short duration of those instruments. Also, the carrying values of our Vermont Industrial Development Authority Bonds ("VIDA") and Connecticut Development Authority Bonds ("CDA") approximate fair value since the rates are adjusted at least monthly. The carrying value of our credit facilities approximates fair value since the rates can change daily. The fair value of our cash equivalents and restricted cash are included in Part II, Item 8, Note 5 - Fair Value.

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, 2009, approximately 5 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 certain transmission customers and 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 5 - FAIR VALUE

Effective January 1, 2008, we adopted FASB's guidance for fair value measurements, as required. The guidance establishes a single, authoritative definition of fair value, prescribes methods for measuring fair value, establishes a fair value hierarchy based on the inputs used to measure fair value and expands disclosures about the use of fair value measurements; however, the guidance does not expand the use of fair value accounting in any new circumstances. The guidance 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."

Valuation Techniques The guidance emphasizes that fair value is not an entity-specific measurement but a market-based measurement utilizing assumptions market participants would use to price the asset or liability. The guidance includes three valuation techniques to be used at initial recognition and subsequent measurement of an asset or liability:

Market Approach: This approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

Income Approach: This approach uses valuation techniques to convert future amounts (cash flows, earnings) to a single present value amount.

Cost Approach: This approach is based on the amount currently required to replace the service capacity of an asset (often referred to as the "current replacement cost").

The valuation technique (or a combination of valuation techniques) utilized to measure fair value is the one that is appropriate given the circumstances and for which sufficient data is available. Techniques must be consistently applied, but a change in the valuation technique is appropriate if new information is available.

Fair Value Hierarchy The guidance establishes a fair value hierarchy ("hierarchy") to prioritize the inputs used in valuation techniques. The hierarchy is designed to indicate the relative reliability of the fair value measure. The highest priority is given to quoted prices in active markets, and the lowest to unobservable data, such as an entity's internal information. The lower the level of the input of a fair value measurement, the more extensive the disclosure requirements. There are three broad levels:

Level 1: Quoted prices (unadjusted) are available in active markets for identical assets or liabilities as of the reporting date. Level 1 includes cash equivalents that consist of money market funds.

Level 2: Pricing inputs are other than quoted prices in active markets included in Level 1, which are directly or indirectly observable as of the reporting date. This value is based on other observable inputs, including quoted prices for similar assets and liabilities in markets that are not active. Level 2 includes investments in our Millstone Decommissioning Trust Funds such as fixed income securities (Treasury securities, other agency and corporate debt) and equity securities.

Level 3: Pricing inputs include significant inputs that are generally less observable. Unobservable inputs may be used to measure the asset or liability where observable inputs are not available. We develop these inputs based on the best information available, including our own data. Level 3 instruments include derivatives related to our forward energy purchases and sales, financial transmission rights and a power-related option contract. There were no changes to our Level 3 fair value measurement methodologies.

Recurring Measures The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that are accounted for at fair value on a recurring basis. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels (dollars in thousands):

	Fair Value as of December 31, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities	$1,382	$2,427		$3,809
Marketable debt securities				
Corporate bonds		328		328
U.S. Government issued debt securities (Agency and Treasury)		889		889
State and municipal		14		14
Other		4		4
Total marketable debt securities		1,235		1,235
Cash equivalents and other	2	36		38
Total investments in securities	1,384	3,698		5,082
Cash equivalents	746			746
Restricted cash	5,369			5,369
Power-related derivatives - current			$622	622
Total assets	$7,499	$3,698	$622	$11,819
Liabilities:				
Power-related derivatives - current	$0	$0	$219	$219
Power-related derivatives - long term	0	0	149	149
Total liabilities	$0	$0	$368	$368

	Fair Value as of December 31, 2008			
	Level 1	Level 2	Level 3	Total
Assets:				
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities		$2,646		$2,646
Marketable debt securities				
Corporate bonds		342		342
U.S. Government issued debt securities (Agency and Treasury)		992		992
State and municipal		133		133
Other		30		30
Total marketable debt securities		1,497		1,497
Cash equivalents and other		60		60
Total investments in securities		4,203		4,203
Cash equivalents	5,028			5,028
Restricted cash	3,636			3,636
Power-related derivatives - current			$12,758	12,758
Power-related derivatives - long term			133	133
Total assets	$8,664	$4,203	$12,891	$25,758
Liabilities:				
Power-related derivatives - current	$0	$0	$2	$2
Power-related derivatives - long term	0	0	4,069	4,069
Total liabilities	$0	$0	$4,071	$4,071

Millstone Decommissioning Trust Our primary valuation technique to measure the fair value of our nuclear decommissioning trust investments is the market approach. Actively traded quoted prices cannot be obtained for the funds in our qualified decommissioning trusts. However, actively traded quoted prices for the underlying securities comprising the funds have been obtained. Due to these observable inputs, fixed income, equity and cash equivalent securities in the qualified fund are classified as Level 2. Equity securities are held directly in our non-qualified trust and actively traded quoted prices for these securities have been obtained. Due to these observable inputs, these equity securities are classified as Level 1.

Cash Equivalents and Restricted Cash We use the market approach to measure the fair values of money market funds included in cash equivalents and restricted cash. Cash equivalents are included in cash and cash equivalents on the Consolidated Balance Sheets. We are able to obtain actively traded quoted prices for these funds.

Power-related Derivatives We estimate the fair values of power-related derivatives based on the best market information available, including the use of internally developed models and broker quotes for forward energy contracts. At the end of 2009 and 2008, we value financial transmission rights using auction clearing prices from the December auctions held by ISO-New England. We also use a binomial tree model and an internally developed long-term price forecast to value a power-related option contract.

Level 3 Changes The following table is a reconciliation of changes in the net fair value of power-related derivatives which are classified as Level 3 in the fair value hierarchy. There were no transfers into or out of Level 3 during the periods presented (dollars in thousands).

	Year ended December 31	
	2009	**2008**
Balance at Beginning of Period	**$8,820**	**($7,110)**
Gains and losses (realized and unrealized)		
Included in earnings	**23,113**	**(8,606)**
Included in Regulatory and other assets/liabilities	**(8,564)**	**15,795**
Purchases, sales, issuances and net settlements	**(23,115)**	**8,741**
Balance at December 31	**$254**	**$8,820**

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 Consolidated Balance Sheet, depending on whether the change in fair value is an unrealized loss or gain. The corresponding offsets are current and long-term assets or liabilities depending on the duration.

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 must 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 the FASB guidance for Regulated Operations.

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 equity securities in the trusts because regulatory authorities limit our ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments. Therefore, we consider all equity securities held by our nuclear decommissioning trusts with fair values below their cost basis to be other-than-temporarily impaired. The FASB guidance for Investments - Debt and Equity Securities, requires impairment of debt securities if: 1) there is the intent to sell a debt security; 2) it is more likely than not that the security will be required to be sold prior to recovery; or 3) the entire unamortized cost of the security is not expected to be recovered. For the majority of the investments shown below, we own a share of the trust fund investments.

In July 2009, we changed one of the fund managers for our available-for-sale equity investments. This resulted in a higher level of investments in available-for-sale securities and proceeds from sale of available-for-sale securities as reported on the Consolidated Statements of Cash Flows. In 2009, we had $0.7 million of realized gains and our realized losses were $0.4 million. The realized losses include $0.2 million of impairments associated with our equity securities; however, there were no permanent impairments or 'credit losses' associated with our debt securities. Additionally, in 2009, we recorded a non-credit loss impairment to our debt securities that is included in unrealized losses. We recorded an impairment of $0.4 million on our Millstone securities in 2008.

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

	As of December 31, 2009			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Marketable equity securities	**$3,107**	**$702**		**$3,809**
Marketable debt securities				
Corporate bonds	**317**	**15**	**($4)**	**328**
U.S. Government issued debt securities (Agency and Treasury)	**850**	**44**	**(5)**	**889**
State and municipal	**13**	**1**		**14**
Other	**4**			**4**
Total marketable debt securities	**1,184**	**60**	**(9)**	**1,235**
Cash equivalents and other	**38**			**38**
Total	**$4,329**	**$762**	**($9)**	**$5,082**

	As of December 31, 2008			
Security Types	Amortized Cost	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Marketable equity securities	$2,406	$240	$0	$2,646
Marketable debt securities				
Corporate bonds	324	18		342
U.S. Government issued debt securities (Agency and Treasury)	926	66		992
State and municipal	127	6		133
Other	30			30
Total marketable debt securities	1,407	90		1,497
Cash equivalents and other	60			60
Total	$3,873	$330	$0	$4,203

Information related to the fair value of debt securities at December 31, 2009 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	$33	$267	$258	$677	$1,235

At December 31, 2009, the fair value of debt securities in an unrealized loss position was $0.3 million. In 2009, the fair value of debt securities in an unrealized loss position for 12 months or greater was not material and there were no unrealized losses associated with debt securities in 2008.

NOTE 7 - RETAIL RATES AND REGULATORY ACCOUNTING

Retail Rates Our retail rates are approved by the PSB after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). 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.

On September 30, 2008, the PSB issued an order approving, with modifications, the alternative regulation plan proposal that we submitted in August 2007. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension. The plan replaces the traditional ratemaking process and allows for quarterly rate adjustments to reflect changes in power supply and transmission-by-others costs ("PCAM" adjustment); annual base rate adjustments to reflect changing costs; and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity will be adjusted annually to reflect one-half of the change in the average yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The earnings sharing adjustment mechanism ("ESAM") within the plan provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to ratepayers in a future period. If the actual return on equity of our regulated business falls between 75 and 100 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and ratepayers. Any earnings shortfall in excess of 100 basis points below the allowed return on equity is recovered from ratepayers. These adjustments are made at the end of each fiscal year.

The PCAM and ESAM adjustments are not subject to PSB suspension, but the PSB may open an investigation and, to the extent it finds, after notice and hearing, that a calculation in the adjustments was inaccurate or reflects costs inappropriate for inclusion in rates, it may require a modification of the associated adjustments to the extent necessary to correct the deficiencies.

On October 31, 2008, we submitted a base rate filing for the rate year commencing January 1, 2009 that reflected a 0.33 percent increase in retail rates. The result of the return on equity adjustment for 2009, in accordance with the plan, was a reduction of 0.44 percent, resulting in an allowed return on equity for 2009 of 9.77 percent. On November 17, 2008, the DPS filed a request for suspension and investigation of our filing. Citing concerns about staffing levels and inadequate supporting documentation for some proposed rate base additions, the DPS recommended a 0.43 percent rate decrease.

On December 17, 2008, we filed a Memorandum of Understanding with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our 2009 retail rates. Pursuant to the Memorandum of Understanding, we agreed to leave rates unchanged, with no increase or decrease, and that we and the DPS would request the PSB to open a docket to resolve the DPS's concerns regarding our level of staffing. On February 13, 2009, the PSB approved the Memorandum of Understanding, and ordered the rate investigation closed.

On February 2, 2009, we filed a motion with the PSB requesting to defer the incremental 2008 storm costs through our alternative regulation plan and collect them in rates through the ESAM over 12 months beginning on July 1, 2009. On February 3, 2009, the DPS filed a letter supporting our motion and on February 12, 2009, the PSB approved the request. The amount of the deferral, based on actual costs, was $3.2 million.

On May 1, 2009, we filed an ESAM report, including supporting documentation, with the PSB requesting that rates be increased 1.15 percent for 12 months beginning with bills rendered July 1, 2009 to recover the $3.2 million of incremental 2008 storm costs. On June 15, 2009, the DPS recommended that the ESAM report be approved as filed. On June 30, 2009, the PSB accepted the DPS recommendation and approved the filing. The rate increase has been implemented as proposed.

The PCAM adjustments for the first, second and third quarters of 2009 were calculated to be over-collections of $0.6 million, $0.5 million and $0.6 million, respectively and each was recorded as a current liability. We filed PCAM reports each quarter, including supporting documentation, with the PSB identifying the over-collections. In each case, the DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. The first and second quarter over-collections were returned to customers over the three months ending September 30, 2009 and December 31, 2009, respectively. The third quarter over-collection is being returned to customers over the three months ending March 31, 2010.

The fourth quarter 2009 PCAM adjustment was calculated to be an over-collection of $1.0 million and is recorded as a current liability at December 31, 2009. On January 29, 2010, we filed a PCAM report, including supporting documentation, with the PSB outlining the over-collection. The over-collection will be returned to customers over three months ending June 30, 2010.

On October 30, 2009, we submitted a base rate filing ("2010 base rate filing") for the rate year commencing January 1, 2010 reflecting an increase in revenues of $16.6 million or a 5.91 percent increase in retail rates. Under our alternative regulation plan, the annual change in the non-power costs, as reflected in our base rate filing, is limited to any increase in the U.S. Consumer Price Index for the northeast ("CPI-NE"), less a 1 percent productivity adjustment. The non-power costs associated with the implementation of our asset management plan are excluded from the non-power cost cap. Our 2010 non-power costs exceeded the non-power cost cap by approximately $1 million and these costs ("disallowed costs") are not included in our 2010 non-power base rates. These disallowed costs will be factored into the earnings-sharing adjustment mechanism when it is calculated at the close of rate year 2010. The allowed rate of return for 2010, calculated in accordance with the plan, is 9.59 percent.

On December 16, 2009, the DPS notified the PSB that they disagreed with the calculation of the CPI-NE factor in our 2010 base rate filing. The DPS believed we should have used a CPI-NE factor of negative 0.7 percent rather than zero which would reduce the increase in base rates to $15.6 million or a 5.58 percent increase in retail rates.

On December 22, 2009, we filed an amended 2010 base rate filing with the PSB. The amended filing reflected a CPI-NE factor of negative 0.7 percent and requested an increase of $15.6 million, or a 5.58 percent increase in retail rates effective with bills rendered January 1, 2010.

On December 31, 2009, the PSB issued its order approving a rate increase of 5.58 percent effective for bills rendered on January 1, 2010.

As part of our 2010 base rate filing, we proposed an amendment to the non-power cost cap formula of our alternative regulation plan to allow an adder for new initiatives arising after the effective date of the plan. The DPS was supportive of the proposal, and the 2010 base rate filing increase approved by the PSB included recovery of costs for two new initiatives. However, the PSB has not yet acted on the proposed amendment. If the PSB ultimately decides not to approve the amendment, we will be required to refund approximately $0.5 million to customers.

Using the methodology specified in our alternative regulation plan, we calculated the 2009 return on equity from the regulated portion of our business to be approximately 9.9 percent. We are required to file this calculation with the PSB by May 1, 2010. No ESAM adjustment was required since this return was within 75 basis points of our 2009 allowed return on equity of 9.77 percent.

Staffing Level Investigation On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS. On March 25, 2009, the PSB convened a prehearing conference where we and the DPS agreed to a procedural schedule. We and the DPS further agreed that the scope of the technical hearings could be narrowed to devising a methodology for deriving productivity measures that would be tracked over time. The parties did not agree, however, as to what the substantive elements of that tracking methodology should be. Accordingly, the PSB ordered that the purpose of hearings in this proceeding would be to resolve this disagreement about the makeup of the productivity tracking methodology. Technical hearings were held in June 2009 and legal briefs were filed in July 2009.

The PSB issued its Order in the case on August 20, 2009. In its decision, the board made no determination that we are over-staffed. We are allowed to increase our 2010 non-power cost cap by $0.2 million, representing the average cost of an additional 2.25 employees beyond the number currently allowed in rates. As recommended by the 2008 business process review report, the PSB order required us to undertake a comprehensive review of our organizational structure, staffing levels and costs to determine the appropriate structure and number of staff we should employ at ratepayer expense.

On November 30, 2009, we filed a Memorandum of Understanding ("Staffing MOU") with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our staffing levels. Under the Staffing MOU, in lieu of retaining a management consultant to perform a comprehensive review of our organizational structure and staffing, we and the DPS have agreed that we will reduce our staffing levels over a five-year period by a total of 17 positions as compared to the 549 positions we had on January 1, 2009. This reduction shall be in addition to the staffing changes contemplated by the implementation of CVPS SmartPower™. We retain discretion in how to achieve the staffing reductions, and the DPS has agreed that it shall not oppose the recovery in rates of all reasonable costs associated with staffing and related compensation during the term of the Staffing MOU, provided that recovery of such costs is otherwise consistent with normal ratemaking standards. Nothing in the Staffing MOU precludes us from seeking to add staff as reasonably necessary in response to new requirements imposed by the state or federal government. The PSB has not yet acted on the MOU.

Regulatory Accounting Under FASB's guidance for regulated operations, 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 through future revenues. In the event that we no longer meet the criteria under accounting for regulated operations and there is not a rate mechanism to recover these costs, we would be required to write off $14.2 million of regulatory assets (total regulatory assets of $46.2 million less pension and postretirement medical costs of $32 million), $1.5 million of other deferred charges - regulatory and $3.9 million of other deferred credits - regulatory. This would result in a total charge to operations of $11.8 million on a pre-tax basis as of December 31, 2009. We would be required to record pre-tax pension and postretirement costs of $31.3 million to Accumulated Other Comprehensive Loss and $0.7 million to Retained Earnings as reductions to stockholders' equity. We would also be required to determine any potential impairment to the carrying costs of deregulated plant. Regulatory assets, certain other deferred charges and other deferred credits are shown in the table below (dollars in thousands).

	December 31, 2009	December 31, 2008
Regulatory assets		
Pension and postretirement medical costs	**$32,033**	$46,911
Nuclear plant dismantling costs	**8,498**	10,049
Nuclear refueling outage costs - Millstone Unit #3	**269**	1,347
Income taxes	**4,389**	4,115
Asset retirement obligations and other	**1,051**	1,052
Total Regulatory assets	**46,240**	63,474
Other deferred charges - regulatory		
Vermont Yankee sale costs (tax)	**673**	673
Deferral of December 2008 storm costs	**0**	4,059
Unrealized losses on power-related derivatives	**368**	4,070
Other	**503**	1,178
Total Other deferred charges - regulatory	**1,544**	9,980
Other deferred credits - regulatory		
Asset retirement obligation - Millstone Unit #3	**2,497**	1,497
Vermont Yankee settlements	**183**	789
Emission allowances and renewable energy credits	**0**	308
Unrealized gains on power-related derivatives	**488**	12,756
Environmental remediation	**0**	1,000
Other	**720**	1,346
Total Other deferred credits - regulatory	**$3,888**	$17,696

The regulatory assets included in the table above are being recovered in retail rates and are supported by written rate orders. 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, nuclear plant dismantling costs, and pension and postretirement medical costs. Other deferred charges – regulatory are supported by PSB-approved accounting orders or approved cost recovery methodologies, allowing cost deferral until recovery in a future rate proceeding. 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.

Regulatory assets for pension and postretirement medical costs are discussed in Part II, Item 8, Note 15 - Pension and Postretirement Medical Benefits. Regulatory assets for nuclear plant dismantling costs are related to our equity interests in Maine Yankee, Connecticut Yankee and Yankee Atomic which are described in Part II, Item 8, Note 3 - Investments in Affiliates. Power-related derivatives are discussed in more detail in Part II, Item 8, Note 5 - Fair Value.

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 stock options, common stock and performance shares. The last stock option awards were made in 2005 and we do not anticipate making additional awards. At December 31, 2009 these plans included:

Plan	Shares Authorized	Stock Options Outstanding	Shares Available for Future Grant
1997 Stock Option Plan - Key Employees	350,000	43,298	0
2000 Stock Option Plan - Key Employees	350,000	182,630	0
Omnibus Stock Plan (a)	450,000	109,369	132,740
Total	1,150,000	335,297	132,740

(a) The 2002 Long-Term Incentive Plan was amended in 2008. The amendments renamed the plan as the Central Vermont Public Service Corporation Omnibus Stock Plan ("Omnibus Stock Plan"), added 100,000 additional shares of our common stock to be issued under the plan and revised the plan to conform to certain other regulatory changes. The adoption of the amendments to the plan was authorized by the PSB on April 23, 2008 and by our shareholders on May 6, 2008.

The Omnibus Stock Plan authorizes the granting of stock options, stock appreciation rights, common shares and performance shares. The plan is intended to encourage stock ownership by recipients. Stock options have not been granted as a form of compensation since 2005 and stock appreciation rights have not been granted.

Total share-based compensation expense recognized in the income statement was $0.9 million in 2009, $0.8 million in 2008 and $0.6 million in 2007. The total income tax benefit recognized in the income statement for share-based compensation was $0.4 million in 2009, $0.3 million in 2008 and $0.2 million in 2007. No compensation costs were capitalized. Cash received from exercise of stock options was $0.4 million in 2009, $1 million in 2008 and $1.1 million in 2007. The tax benefit realized for the tax deductions from option exercises and performance shares issued was $0.3 million in 2009 and $0.4 million in 2008. The tax benefit realized for the tax deductions from option exercises was $0.4 million in 2007. 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 original issue 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 not been settled in cash.

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 2009 follows:

	Shares	Weighted Average Exercise Price
Options outstanding and exercisable at January 1	378,957	$17.55
Exercised	36,160	$10.56
Granted	0	
Forfeited	2,500	
Expired	5,000	
Options outstanding and exercisable at December 31	335,297	$18.14

The total intrinsic value of stock options exercised during the last three years was $0.3 million in 2009, $0.6 million in 2008 and $1 million in 2007. The aggregate intrinsic value of options outstanding and exercisable as of December 31, 2009 was $0.9 million. The weighted-average remaining contractual life for options outstanding and exercisable as of December 31, 2009 was 3.3 years.

Common and Nonvested Shares The fair value of common stock granted to key employees and non-employee directors 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 2009 follows:

	Shares	**Weighted Average Grant-Date Fair Value**
Nonvested at January 1	1,000	$18.15
Granted	10,660	$18.04
Vested	(5,530)	$18.19
Deferred	(6,130)	$17.93
Forfeited		
Nonvested at December 31	0	$0.00

In 2009, common stock was granted as part of the Board of Directors' annual retainer. These shares vest immediately, however, individual directors can elect to defer receipt of their retainer under the terms of the Deferred Compensation Plan for Directors and Officers. Compensation expense was $0.2 million in 2009, $0.2 million in 2008 and $0.3 million in 2007. Unearned compensation expense at December 31, 2009 was of a nominal amount.

The weighted-average grant-date fair value of shares granted was $18.04 in 2009, $21.18 per share in 2008 and $32.22 per share in 2007. The fair value of shares vested totaled approximately $0.1 million in 2009, $0.1 million in 2008 and $0.2 million in 2007.

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 2009 was $16.61 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 2009 was $21.59 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 during the past three years are shown in the table below.

	2009	2008	2007
Volatility	**42.30%**	32.20%	25.97%
Risk-free rate of return	**1.09%**	2.76%	4.68%
Dividend yield	**4.07%**	3.08%	4.04%
Term (years)	**3**	3	3

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 2009 follows:

	Shares	Weighted Average Grant-Date Fair Value
Outstanding at January 1	50,300	$25.00
Contingently granted for the 2009 - 2011 performance cycle	29,900	$19.10
Vested for the 2007 - 2009 performance cycle (a)	(28,600)	$21.81
Forfeited		
Outstanding at December 31	51,600	$23.35

(a) Based on 100 percent performance level.

Compensation expense for performance share plans amounted to $0.7 million in 2009, $0.6 million in 2008 and $0.3 million in 2007. Unrecognized compensation expense for outstanding performance shares based on anticipated performance levels as of December 31, 2009 is approximately $0.5 million and is expected to be recognized over 1.5 years.

At December 31, 2009, the fair value of performance shares that were earned or vested, including dividend equivalents, based on goals that were achieved for the 2007 - 2009 performance cycle and were pending Board of Director approval, was $0.7 million.

In the first quarter of 2009, a total of 39,517 common shares were issued for the 2006 - 2008 performance cycle, of which the participants withheld receipt of 14,424 shares to satisfy withholding tax obligations. The fair value of shares vested at December 31, 2008 was $0.9 million based on the goals that were achieved for the 2006 - 2008 performance cycle.

In the first quarter of 2008, a total of 22,701 common shares were issued for the 2005 - 2007 performance cycle, of which the participants withheld receipt of 7,612 shares to satisfy withholding tax obligations. The fair value of shares vested at December 31, 2007 was $0.7 million based on the goals that were achieved for the 2005 - 2007 performance cycle.

NOTE 9 - COMMON STOCK

On November 18, 2008, we entered into an underwriting agreement with a financial institution. Pursuant to the agreement, we agreed to sell 1,190,000 shares of our common stock ($6 par value per share), plus an additional 119,000 shares should the underwriters exercise their 30-day option to cover over-allotments, if any. The shares were sold to the underwriters at a net price of $17.86 per share for sale to the public at a price of $19.00 per share. On November 24, 2008, we issued 1,190,000 shares, resulting in net proceeds of approximately $21.3 million. No additional shares were issued to the underwriters as there were no over-allotments. The net proceeds of the offering were used for general corporate purposes, including the repayment of debt, capital expenditures, investments in Transco and working capital requirements.

NOTE 10 - TREASURY STOCK

Treasury stock is recorded at the average cost of $22.75 per share, including additional costs, 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. In September 2009, we ceased using Treasury shares and began using original issue shares to meet reinvestment obligations under the Dividend Reinvestment Plan.

NOTE 11 - 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):

	2009	2008
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, 2009, a total of 90,538 shares were outstanding, including 80,538 that are not subject to mandatory redemption and are listed in the table above, and 10,000 that are subject to mandatory redemption and described in Part II, Item 8, Note 12 - 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 2009, 2008 or 2007.

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, 2009, 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	$5.50
4.650% Series	$5.00
4.750% Series	$1.00
5.375% Series	$5.00

NOTE 12 - 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 10,000 at December 31, 2009, 20,000 at December 31, 2008 and 30,000 at December 31, 2007. All of the provisions described in Part II, Item 8, Note 11 - 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, 2009, the premium payable in the event of voluntary liquidation, dissolution or winding up of our affairs was at $1.245 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 million (10,000 shares at par value) per annum. We may, at our option, also redeem at par an additional non-cumulative $1 million annually. We are scheduled to make our last annual payment of $1 million in 2010 under the mandatory redemption requirements. Thereafter the 8.3 Percent Series Preferred Stock will be fully redeemed. In the fourth quarter of 2009 and 2008, we paid our transfer agent $1 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 $0.1 million in 2009, $0.2 million in 2008 and 2007.

NOTE 13 - LONG-TERM DEBT, NOTES PAYABLE AND CREDIT FACILITY

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

	December 31, 2009	December 31, 2008
First Mortgage Bonds		
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
6.83%, Series UU, due 2028	**60,000**	60,000
8.91%, Series JJ, due 2031	**15,000**	15,000
Revenue Bonds		
New Hampshire Industrial Development Authority Bonds ("NHIDA")		
3.75%, due 2009	**0**	5,450
Vermont Industrial Development Authority Bonds ("VIDA")*		
Variable, due 2013 (0.75% at December 31, 2009 and 0.85% at December 31, 2008)	**5,800**	5,800
Connecticut Development Authority Bonds ("CDA")*		
Variable, due 2015 (0.75% at December 31, 2009 and 1% at December 31, 2008)	**5,000**	5,000
Credit Facility		
$40 million unsecured revolving credit facility (0.8875 % at December 31, 2009)	**23,311**	0
Total long-term debt, notes payable and credit facility	**201,611**	183,750
Less current amount payable, due within one year	**0**	(16,250)
Total long-term debt, notes payable and credit facility, less current portion	**$201,611**	$167,500

* The VIDA and CDA bonds were included in Notes Payable at December 31, 2008.

First Mortgage Bonds: On May 15, 2008, we issued $60 million of our First Mortgage 6.83 percent Bonds, Series UU due May 15, 2028. The issuance was pursuant to our Indenture of Mortgage dated as of October 1, 1929, as amended and supplemented by supplemental indentures, including the Forty-Sixth Supplemental Indenture, dated May 1, 2008. The Bonds were issued in a private placement in reliance on exemptions from registration under the Securities Act of 1933, as amended, pursuant to the terms of a Bond Purchase Agreement, dated May 15, 2008, among us and 10 institutional investors. The bond issuance required prior approval by the PSB, which we received on April 23, 2008.

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

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 $0 in 2010, $20 million in 2011, $0 in 2012, $0 in 2013 and $0 in 2014.

Revenue bonds: The NHIDA bonds were pollution-control revenue bonds that carried an interest reset provision. These bonds matured on December 1, 2009 and were included in the current portion of long-term debt at December 31, 2008.

The CDA and VIDA 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 the 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. Because of the three-year term of the new letters of credit discussed below, these revenue bonds were reclassified from Notes Payable to Long-Term Debt as of September 30, 2009.

Letters of credit: We have two outstanding unsecured letters of credit, issued by one bank, that support the CDA and VIDA revenue bonds. These letters of credit total $11.1 million in support of two separate issues of industrial development revenue bonds totaling $10.8 million. We pay an annual fee of 2.4 percent on the letters of credit, based on our unsecured issuer rating. These letters of credit expire on November 30, 2012. The letters of credit contain cross-default provisions to our wholly owned subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or insolvency. At December 31, 2009, there were no amounts drawn under these letters of credit.

Covenants: Our long-term debt indentures, letters of credit, credit facilities and material agreements contain 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, 2009, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit, credit facilities and material agreements. A significant reduction in future earnings or a significant reduction to common equity could restrict the payment of common and preferred dividends or could cause us to violate our maintenance covenants. If we were to default on our covenant, the lenders could take such actions as terminate their obligations, declare all amounts outstanding or due immediately payable, or take possession of or foreclose on mortgaged property.

Credit Facility: We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated November 3, 2008. It contains financial and non-financial covenants. 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 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 0.15 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.7 percent on the average daily amount of letters of credit outstanding, all based on our unsecured issuer 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). 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, 2009 $23.3 million in loans and no letters of credit were outstanding under this credit facility.

We also have a 364-day, $15 million unsecured revolving credit facility with a different lending institution pursuant to a credit agreement dated December 30, 2009. The purpose of and our obligation under this credit agreement is the same as described above. Financing terms and costs include an annual commitment fee of 0.5 percent on the unused balance and a commission of 2.0 percent on the average daily amount of letters of credit outstanding. Interest on the outstanding balance of amounts borrowed under various interest options is based on our unsecured issuer rating. This facility does not contain a material adverse effect clause. At December 31, 2009 there were no borrowings or letters of credit outstanding under this credit facility.

Dividend and Optional Stock Redemption Restrictions: Our revolving credit facilities described above restricts optional redemptions of capital stock and other restricted payments as defined. 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, $75.7 million of retained earnings was not subject to such restriction at December 31, 2009. 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 14 - POWER-RELATED DERIVATIVES

We are exposed to certain risks in managing our power supply resources to serve our customers, and we use derivative financial instruments to manage those risks. The primary risk managed by using derivative financial instruments is commodity price risk. Currently, our power supply forecast shows energy purchase and production amounts in excess of our load requirements through 2011. Because of this projected power surplus, we entered into a 2010 forward power sale contract to reduce price volatility of our net power costs. Deliveries under this sale contract are excused during any period of time that Vermont Yankee is not operating as a result of an unplanned outage. On occasion, we will forecast a temporary power supply shortage such as when Vermont Yankee becomes unavailable. We typically enter into short-term forward power purchase contracts to cover a portion of these expected power supply shortages, which helps to reduce price volatility in our net power costs. The next scheduled Vermont Yankee outage is planned for the spring of 2010, and we have entered into one short-term replacement power purchase for the estimated duration of this outage. Beginning in March 2012, our power supply forecast shows that our load requirements will exceed our energy purchase and production amounts, as certain committed long-term power purchase contracts begin to expire.

Several years ago, we entered into a long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice ("Hydro-Quebec Sellback #3"). In addition, we are able to economically hedge our exposure to congestion charges that result from constraints on the transmission system with FTRs. FTRs are awarded to the successful bidders in periodic auctions administered by ISO-New England. We do not use derivative financial instruments for trading or other purposes.

Accounting for power-related derivatives is discussed in Part II, Item 8, Note 1- Business Organization and Summary of Significant Accounting Policies - Derivative Financial Instruments.

As of December 31, 2009, we had the following outstanding power-related derivative contracts:

Commodity	mWh (000s)
Forward Energy Contracts	517.3
Financial Transmission Rights	2,067.9
Hydro-Quebec Sellback #3	136.9

We recognized the following amounts in the Consolidated Statements of Income in connection with derivative financial instruments for the years ended December 31(dollars in thousands):

	2009	2008
Net realized gains (losses) reported in operating revenues	**$23,226**	($8,596)
Net realized gains (losses) reported in purchased power	**($113)**	($10)

Realized gains and losses on derivative instruments are conveyed to or recovered from customers through the PCAM and have no impact on results of operations. Derivative transactions and related collateral requirements are included in net cash flows from operating activities in the Consolidated Statements of Cash Flows. For information on the location and amounts of derivative fair values on the Consolidated Balance Sheets see Part II, Item 8, Note 5 - Fair Value.

Certain of our power-related derivative instruments contain provisions for performance assurance that may include the posting of collateral in the form of cash or letters of credit, or other credit enhancements. Our counterparties will typically establish collateral thresholds that represent credit limits, and these credit limits vary depending on our credit rating. If our current credit rating were to decline, certain counterparties could request immediate payment and full overnight ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2009 is $0.2 million, for which we were not required to post collateral since our issuer credit rating from Moody's is Baa3. If Moody's were to lower our corporate credit rating to below Ba1, we would be required to post an additional $0.8 million of collateral with our counterparty, upon request. For information concerning performance assurance, see Part II, Item 8, Note 17 - Commitments and Contingencies - Performance Assurance.

NOTE 15 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

We have a qualified, non-contributory, defined-benefit pension plan ("Pension Plan") covering unionized and non-unionized employees subject to certain eligibility criteria. Under the terms of the Pension Plan, employees are vested after completing five years of service, and can receive a pension benefit when they are at least age 55 with a minimum of 10 years of service. They are eligible to choose between various payment options such as a monthly benefit or a one-time lump-sum amount depending on factors such as years of service earned at the date of retirement. Our funding policy is to contribute to the pension trust fund the greater of the annual actuarial cost or the statutory minimum. We are not required by our union contract to contribute to multi-employer plans. At the end of 2008, we adopted the Fully Generational mortality table. This replaces the RP-2000 mortality 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 a 401(h) Subaccount in the Pension Plan. Retirees under the age of 65 ("pre-age 65") participate in plan options similar to active employees. Retirees at or over the age of 65 ("post-age 65") receive limited coverage with a $10,000 annual individual maximum. Company contributions to retiree medical premiums are capped for employees retiring after 1995 at $0.3 million per year for pre-age 65 retirees and are capped at a nominal amount for post-age 65 retirees. There are no retiree contributions for pre-1996 retirees.

Beginning in 2009, the postretirement benefit is being enhanced with sharing of one-half of the Medicare Part D subsidy that we receive. Under this enhancement, we will split the shared subsidy portion evenly between the pre-age 65 and post-age 65 retiree plans. Medicare Part D reduced our postretirement medical benefit costs by $1.7 million in 2009, $0.4 million in 2008 and $0.6 million in 2007.

As part of our contract with the IBEW Local 300 in December 2008, the parties agreed, subject to ratification by the Board of Directors, to close the pension plan to employees hired after a future date to be determined (the "conversion date"). On November 9, 2009, our board of directors voted to approve changes to the pension plan and 401(k) plan with a conversion date of April 1, 2010. Employees hired after the conversion date will be given, in addition to the existing match on 401(k) contributions up to 4.25 percent, a core 401(k) contribution of 3 percent of base pay, or a total of up to 7.25 percent. The core contribution will be subject to a three-year cliff vesting schedule. For employees hired before the conversion date, the current pension benefits will remain in effect. In addition, employees hired before the conversion date will receive a core 401(k) contribution of .50 percent of eligible base pay into the 401(k) plan in addition to the current 401(k) company match of up to 4.25 percent, or a total of up to 4.75 percent. The pension plan will also be enhanced on the conversion date by offering the so-called "Rule of 85." Under the Rule of 85, if an employee is at least 55 years old with 10 years of service and their combined service and age totals at least 85, they will be eligible for an unreduced pension benefit. At December 31, 2009, this pension plan amendment increased our pension benefit obligation by $1.3 million and will increase our 2010 annual pension benefit cost by $0.2 million. At December 31, 2009, the amendment increased our postretirement medical obligation by $0.1 million and will increase our 2010 annual postretirement medical cost by $0.1 million. Ultimate costs over time will be based on actual retirement patterns.

FASB's guidance for employee retirement benefits 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.

Benefit Obligation The changes in benefit obligation for pension and postretirement medical benefits at the December 31, 2009 and December 31, 2008 measurement dates follow (dollars in thousands):

	Pension Benefits		Postretirement Medical Benefits	
	2009	2008	**2009**	2008
Benefit obligation at beginning of measurement date	**$106,236**	$96,050	**$28,553**	$26,520
Effect of eliminating early measurement date	**0**	884	**0**	66
Service cost	**3,783**	3,291	**710**	621
Interest cost	**6,608**	6,092	**1,712**	1,611
Plan participants' contributions	**0**	0	**639**	1,057
Actuarial loss (gain)	**3,014**	4,319	**(1,119)**	(950)
Gross benefits paid	**(3,934)**	(4,400)	**(2,298)**	(2,502)
less: federal subsidy on benefits paid	**0**	0	**209**	230
Plan amendments	**1,251**	0	**455**	1,900
Projected obligation as of measurement date (December 31)	**$116,958**	$106,236	**$28,861**	$28,553
Accumulated obligation as of measurement date (December 31)	**$96,604**	$87,310	**n/a**	n/a

The reduction in our accumulated postretirement benefit obligation due to the impact of the Medicare Part D subsidy is $5.4 million for 2009 and $3.5 million for 2008.

The present value of future contributions from Postretirement Plan participants was $36.0 million for 2009 and $36.8 million for 2008.

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at the December 31 measurement date for 2009 and 2008 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. 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	
	2009	2008	**2009**	2008
Discount rates	**6.00%**	6.15%	**5.50%**	6.05%
Rate of increase in future compensation levels	**4.25%**	4.25%	**4.25%**	4.25%

For measurement purposes, a 9 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2009, for pre-age 65 and post-age 65 participant claims costs. The rate is assumed to decrease 0.5 percent each year until 2017 until an ultimate trend rate of 5.0 percent is reached.

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):

	Increase	Decrease
Effect on postretirement medical benefit obligation as of December 31, 2009	$1,956	($1,680)
Effect on aggregate service and interest costs	$241	($196)

Asset Allocation The asset allocations at the measurement date for 2009 and 2008, and the target allocation for 2010, by asset category, are as follows:

	Pension Plan			Postretirement Medical Plan		
	2010 Target	**2009**	2008	**2010 Target**	**2009**	2008
Equity securities	**61%**	62%	44%	**60%**	60%	67%
Debt securities	**39%**	38%	37%	**40%**	38%	33%
Other	**0%**	0%	19%	**0%**	2%	0%
Total	**100%**	100%	100%	**100%**	100%	100%

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 61 percent of plan assets be invested in equity securities and 39 percent of plan assets be invested in debt securities. The debt securities are comprised of long-duration bonds to match changes in plan liabilities. In response to market conditions, our pension trust committee voted to temporarily revise our target allocation in mid-December 2008, but we returned to the target asset allocation shown above in mid-2009.

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. Current guidelines specify generally that 60 percent of the plan assets be invested in equity securities and 40 percent be invested in debt securities. Fixed-income securities are of a shorter duration to better match the cash flows of the postretirement medical obligation.

Concentrations of Risk Benefit plan assets that potentially expose us to concentrations of risk include, but are not limited to, significant investments in a single entity, industry, country, commodity or type of security.

To mitigate concentrations of risk arising from our benefit plan investments in debt and equity securities, we pursue a range of investment strategies using a well-diversified array of publicly traded equity and fixed income funds. We also employ a "liability-driven" investing strategy in our pension portfolio, which is a strategy that matches the duration of liabilities and assets to mitigate the negative impact that movements in the interest rates can have on our benefit obligations and funded status. Approximately 25 percent of our liabilities are matched with plan assets.

Change in Plan Assets The changes in Plan assets at the December 31, 2009 and 2008 measurement dates follow (dollars in thousands):

	Pension Plan		Postretirement Medical Plan	
	2009	2008	**2009**	2008
Fair value of plan assets at beginning of measurement date	**$79,178**	$94,356	**$9,249**	$13,264
Effect of eliminating early measurement date	**0**	369	**0**	(22)
Actual return on plan assets	**19,535**	(14,209)	**3,381**	(5,652)
Employer contributions	**2,426**	3,062	**4,057**	3,104
Plan participants' contributions	**0**	0	**638**	1,057
Gross benefits paid	**(3,934)**	(4,400)	**(2,298)**	(2,502)
Fair value of assets as of measurement date (December 31)	**$97,205**	$79,178	**$15,027**	$9,249

Funded Status The Plans' funded status at December 31 was as follows (dollars in thousands):

	Pension Plan		Postretirement Medical Plan	
	2009	2008	**2009**	2008
Fair value of assets	**$97,205**	$79,178	**$15,027**	$9,249
Benefit obligation	**(116,958)**	(106,236)	**(28,861)**	(28,553)
Funded Status	**($19,753)**	($27,058)	**($13,834)**	($19,304)

The increase in the Pension Plan funded status of $7.3 million for 2009 versus 2008 resulted from a increase of $18 million in the fair value of assets as shown in the table above, and an increase of $10.7 million in the benefit obligation, primarily due to actual gains on plan assets as shown in the tables above and changes in actuarial assumptions.

The increase in the Postretirement Medical Plan funded status of $5.5 million for 2009 versus 2008 resulted from an increase of $5.8 million in the fair value of assets as shown in the table above, and an increase of $0.3 million in the benefit obligation, primarily due to the reasons described above and employer contributions.

Fair Value Measures As of December 31, 2009, we adopted FASB guidance that requires additional information about the fair value measurements of plan assets that must be disclosed separately for each annual period for each plan asset category.

Valuation Techniques Fair value guidance emphasizes that market-based measurement should be based on assumptions that market participants would use to price the benefit plan assets. The fair value guidance includes three valuation techniques to be used at the initial recognition and subsequent measurement of benefit plan assets: 1) Market Approach; 2) Income Approach; and 3) Cost Approach. Also see Part II, Item 8, Note 5 - Fair Value for additional information about these valuation techniques.

The valuation technique used to determine the fair value of the debt and equity securities included in our pension and postretirement medical trust funds is the market approach. These securities are considered to be Level 1 in the fair value hierarchy since quoted prices are available in active markets for these assets.

Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the benefit plan assets and their placement within the fair value hierarchy levels. The following table sets forth by level within the fair value hierarchy our Pension Plan and Postretirement Medical Plan assets that are measured at fair value (dollars in thousands):

	Target Allocation 2010	Pension Plan Fair Value as of December 31, 2009			
		Level 1	Level 2	Level 3	Total
Marketable equity securities					
U.S. Large cap	38%	$37,775			$37,775
U.S. Small and mid cap	9%	8,897			$8,897
International	14%	13,690			$13,690
Total marketable equity securities	61%	60,362	0	0	$60,362
Marketable debt securities					$0
Corporate bonds	33%	19,859			$19,859
U.S. Government issued debt securities		9,244			$9,244
U.S. Agency debt		560			$560
Non-corporate		370			$370
High yield debt	3%	3,197			$3,197
Emerging markets debt	3%	2,873			$2,873
Other		566			$566
Total marketable debt securities	39%	36,669	0	0	$36,669
Other		174			$174
Total	100%	$97,205	$0	$0	$97,205

	Target Allocation 2010	Postretirement Medical Plan Fair Value as of December 31, 2009 Level 1	Level 2	Level 3	Total
Marketable equity securities					
U. S. Large cap	35%	5,381			$5,381
U. S. Small and mid cap	9%	1,372			$1,372
International	16%	2,414			$2,414
Other		0			$0
Total marketable equity securities	60%	9,167	0	0	$9,167
Marketable debt securities					$0
Corporate bonds	35%	1,383			$1,383
U.S. Government issued debt securities		689			$689
U.S. Agency debt		1,587			$1,587
State and municipal		14			$14
High yield debt	5%	790			$790
Other		1,421			$1,421
Total marketable debt securities	40%	5,884	0	0	$5,884
Cash and cash equivalents		252			$252
Other		29			$29
Total Fair Value	100%	15,332	0	0	$15,332
Less amounts due from Trust to CVPS at December 31, 2009					($305)
Net Plan Assets					$15,027

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 2009	2008	Postretirement Medical Benefits 2009	2008
Current liability	**$0**	$0	**($201)**	$0
Non-current liability	**(19,753)**	(27,058)	**(13,633)**	(19,304)
Total	**($19,753)**	($27,058)	**($13,834)**	($19,304)

At December 31, 2009, the Postretirement Medical Plan non-current liability shown above included an actuarial estimate of $0.2 million related to our Medicare Part D subsidy payments expected in the first quarter of 2010.

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, 2009 consisted of (dollars in thousands):

	Pension Benefits Regulatory Asset	AOCL	Total	Postretirement Medical Benefits Regulatory Asset	AOCL	Total
Net actuarial loss	$16,694	$51	$16,745	$10,859	$33	$10,892
Prior service cost	2,999	9	3,008	2,070	6	2,076
Transition obligation	0		0	702	2	704
Net amount recognized	$19,693	$60	$19,753	$13,631	$41	$13,672

The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2008 consisted of (dollars in thousands):

	Pension Benefits			**Postretirement Medical Benefits**		
	Regulatory Asset	**AOCL**	**Total**	**Regulatory Asset**	**AOCL**	**Total**
Net actuarial loss	$24,883	$76	$24,959	$16,074	$48	$16,122
Prior service cost	2,093	6	2,099	1,894	6	1,900
Transition obligation	0	0	0	957	3	960
Net amount recognized	$26,976	$82	$27,058	$18,925	$57	$18,982

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	($8,189)	($25)	($8,214)	($3,703)	($11)	($3,714)
Amortization of actuarial loss	0		0	(1,511)	(5)	(1,516)
Current year prior service cost	1,247	4	1,251	454	1	455
Amortization of prior service cost	(341)	(1)	(342)	(278)	(1)	(279)
Amortization of transition obligation	0		0	(255)	(1)	(256)
Net amount recognized	($7,283)	($22)	($7,305)	($5,293)	($17)	($5,310)

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

	Pension Benefits			**Postretirement Benefits**		
	2009	2008	2007	**2009**	2008	2007
Service cost	**$3,783**	$3,291	$3,552	**$710**	$621	$578
Interest cost	**6,608**	6,092	6,242	**1,712**	1,611	1,507
Expected return on plan assets	**(8,306)**	(7,323)	(6,719)	**(785)**	(1,067)	(932)
Amortization of net actuarial loss	**0**	0	582	**1,516**	1,052	1,051
Amortization of prior service cost	**342**	389	399	**279**	0	0
Amortization of transition obligation	**0**	0	0	**256**	256	256
Net periodic benefit cost	**2,427**	2,449	4,056	**3,688**	2,473	2,460
Less amounts capitalized	**311**	405	693	**473**	409	420
Net benefit costs expensed	**$2,116**	$2,044	$3,363	**$3,215**	$2,064	$2,040

Benefit Cost Assumptions Weighted average assumptions are used to determine our annual benefit costs. Beginning in 2008, the weighted average assumptions shown in the table below were set at December 31. The 2007 weighted average assumptions were set at September 30.

	Pension Benefits			**Postretirement Medical Benefits**		
	2009	2008	2007	**2009**	2008	2007
Weighted-average discount rates	**6.15%**	6.30%	5.95%	**6.05%**	6.15%	5.80%
Expected long-term return on assets	**7.85%**	8.25%	8.25%	**7.85%**	8.25%	8.25%
Rate of increase in future compensation levels	**4.25%**	4.25%	4.25%	**4.25%**	4.25%	4.25%

2010 Cost Amortizations: The estimated amounts that will be amortized from regulatory assets and accumulated other comprehensive income into net periodic benefit cost in 2010 are as follows (dollars in thousands):

	Pension Benefits	Postretirement Medical Benefits
Actuarial loss	$0	$969
Prior service cost	428	279
Transition benefit obligation	0	256
Total	$428	$1,504

Expected Long-Term Rate of Return on Plan Assets The expected long-term rate of return on assets shown in the table above was used to calculate the 2009 pension and postretirement medical benefit expenses. The expected long-term rate of return on assets used to calculate these expenses for 2010 will be 7.85 percent.

In formulating the 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.

In 2009 the Pension Plan assets earned a return of 25.2 percent, net of fees. Due to historic underperformance in global financial markets, the Pension Plan assets realized a loss of 12.2 percent, net for the Plan year ended December 31, 2008. For the Plan year ended December 31, 2007 the Pension Plan assets earned a return of 12.8 percent, net.

Trust Fund Contributions The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. In 2009, we contributed $2.4 million to the pension trust fund and $4.1 million to the postretirement medical trust funds.

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 2010, approximately $8.2 million will be paid from the Pension Plan trust fund, and $2.3 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			
2010	$3,300	$3,000	
Expected Benefit Payments			
2010	$8,183	$2,317	$230
2011	7,685	2,420	248
2012	10,886	2,509	267
2013	8,058	2,642	286
2014	9,697	2,750	305
2015 - 2019	48,772	13,763	1,916

As of December 31, 2009, the Medicare Part D subsidy reduced the postretirement benefit obligation by $5.4 million and reduced the 2009 net periodic benefit cost by $1.7 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 non-accumulating post-employment long-term disability benefits in accordance with FASB's guidance for Contingencies. For 2009, the year-end post-employment medical benefit obligation was $1.2 million, of which $1.1 million was recorded as Accrued pension and medical benefit obligations and $0.1 million was recorded as Other current liabilities. The 2008 year-end post-employment medical benefit obligation was $1.6 million, of which $1.5 million was recorded as Accrued pension and medical benefit obligations and $0.1 million was recorded as Other current liabilities. The pre-tax post-employment benefit costs charged to expense (credit), including insurance premiums, were $(0.1) million in 2009, $0.1 million in 2008 and $0.2 million in 2007.

401(k) Savings Plan Most eligible employees choose to participate in our 401(k) Savings Plan. 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 a maximum of 4.0 percent to a maximum of 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 $1.5 million in 2009, $1.4 million in 2008 and $1.3 million in 2007.

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.

For 2009, the accumulated year-end SERP benefit obligation, based on a discount rate of 5.05 percent, was $3.6 million, of which $3.4 million was recorded as Accrued pension and benefit obligations and $0.2 million was recorded as Other current liabilities in the Consolidated Balance Sheets. The 2008 accumulated year-end SERP benefit obligation was $3.6 million, of which $3.3 million was recorded as Accrued pension and benefit obligations and $0.3 million was recorded as Other current liabilities.

The accumulated SERP benefit obligation in 2009 included an immaterial comprehensive loss. The accumulated SERP benefit obligation included a comprehensive gain of $0.3 million in 2008 and $0.2 million in 2007. The pre-tax SERP benefit costs charged to expense totaled $0.3 million in 2009, $0.3 million in 2008 and $0.4 million in 2007.

Benefits are funded through life insurance policies held in a Rabbi Trust. Rabbi Trust assets are not considered plan assets for accounting purposes. The year-end balance included in Investments and Other Assets on our Consolidated Balance Sheets was $6.5 million in 2009 and $5.5 million in 2008. Changes in cash surrender value are included in Other income on our Consolidated Statements of Income. These pre-tax amounts were an increase of $0.6 million for 2009, a decrease of $2.6 million for 2008 and a decrease of $0.2 million for 2007.

NOTE 16 - INCOME TAXES

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

	2009	2008	2007
Federal:			
Current	**$250**	($6,636)	$2,899
Deferred	**9,003**	15,398	2,566
Investment tax credits, net	**(320)**	(379)	(379)
Valuation allowance	**99**	(99)	0
	9,032	8,284	5,086
State:			
Current	**790**	519	1,124
Deferred	**1,134**	1,654	539
Valuation allowance	**(283)**	283	0
	1,641	2,456	1,663
Total federal and state income taxes	**$10,673**	$10,740	$6,749
Federal and state income taxes charged to:			
Operating expenses	**$5,033**	$4,878	$5,291
Other income	**5,640**	5,862	1,458
	$10,673	$10,740	$6,749

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):

	2009	2008	2007
Income before income tax	**$31,423**	$27,125	$22,553
Federal statutory rate	35.0%	35.0%	35.0%
Federal statutory tax expense	**10,998**	9,494	7,894
Increase (benefit) in taxes resulting from:			
Dividend received deduction	**(584)**	(408)	(647)
State income taxes net of federal tax benefit	**773**	1,695	1,106
Investment credit amortization	**(320)**	(379)	(379)
Renewable Electricity Credit	**(233)**	(249)	(275)
AFUDC equity	**109**	109	198
Life insurance	**(451)**	680	(139)
Medicare Part D	**(402)**	(157)	(193)
Domestic production activities deduction	**0**	0	(147)
Valuation allowance	**99**	(99)	0
Other	**684**	54	(669)
Total income tax expense	**$10,673**	$10,740	$6,749
Effective combined federal and state income tax rate	34.0%	39.6%	29.9%

We follow FASB's guidance and methodology for estimating and reporting amounts associated with uncertain tax positions and we adopted the related guidance on January 1, 2007, as required. Upon adoption, 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.

During 2009, unrecognized tax benefits were reduced by $0.7 million, which due to the impact of deferred tax accounting, resulted in a $0.4 million reduction in GAAP tax expenses, resulting in a reduction in the effective tax rate. The $0.4 million impact on the current year effective tax rate is the net of a $0.6 million decrease in state unrecognized tax benefits with the reversal of its associated $0.2 million federal tax benefit. During 2008, unrecognized tax benefits were reduced by $0.2 million, which due to the impact of deferred tax accounting, had a nominal impact on the effective tax rate. In 2007, we increased our estimate of gross unrecognized tax benefits by $1.9 million, which due to the impact of adoption guidelines and deferred tax accounting, had a nominal impact on the effective tax rate.

FASB's guidance for income taxes 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 was no valuation allowance recorded for the year ending 2007. During December 2008, we established a $0.2 million valuation allowance. At issue was the ability to utilize a state capital loss carryforward prior to the expiration of the carryforward period. Due to information obtained during 2009, we now believe it is more likely than not that the capital loss will be utilized during the five-year carryforward period and have reversed the valuation allowance.

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):

	2009	2008
Deferred tax assets - current		
Reserves for uncollectible accounts	**$1,450**	$885
Deferred compensation and pension	**938**	975
Environmental costs accrual	**274**	307
Loss contingency accrual	**485**	485
Active medical accrual	**332**	379
Self insurance reserve	**433**	243
PCAM	**616**	0
Other accruals	**446**	149
Total deferred tax assets - current	**4,974**	3,423
Deferred tax liabilities - current		
Property tax accruals	**382**	304
Prepaid insurance	**400**	382
Derivative instruments	**252**	5,115
ESAM	**589**	0
Total deferred tax liabilities - current	**1,623**	5,801
Net deferred tax assets - current	**3,351**	(2,378)
Deferred tax assets - long term		
Accruals and other reserves not currently deductible	**2,042**	3,685
Millstone decommissioning costs	**2,060**	1,703
Contributions in aid of construction	**1,907**	2,111
Loss on terminated power contract	**2,423**	2,908
Derivative instruments	**258**	6,818
Pension and postretirement medical liability	**15,553**	18,793
Total deferred tax assets - long term	**24,243**	36,018
Less valuation allowance	**0**	(184)
Net deferred tax assets - long-term	**24,243**	35,834

Deferred tax liabilities - long term		
Property, plant and equipment	**53,785**	45,755
Benefits - regulatory asset	**12,981**	19,011
Investments	**13,338**	9,465
ESAM	**0**	1,645
Other	**3,354**	5,272
Total deferred tax liabilities - long term	**83,458**	81,148
Net deferred tax liabilities - long term	**59,215**	45,314
Net deferred tax liabilities	**\$55,864**	\$47,692

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

	2009	2008
Total deferred tax liabilities - current and long-term	**\$85,081**	\$86,949
Less total deferred tax assets - current and long-term	**29,217**	39,257
Net deferred tax liabilities	**\$55,864**	\$47,692

NOTE 17 - COMMITMENTS AND CONTINGENCIES

Long-Term Power Purchases *Vermont Yankee:* We are purchasing our entitlement share of Vermont Yankee plant output through the PPA between Entergy-Vermont Yankee and VYNPC. VYNPC's entitlement to plant output is 83 percent and our share of plant output is 29 percent; our nominal entitlement is approximately 180 MW. We have one secondary purchaser that receives less than 0.5 percent of our entitlement.

Entergy-Vermont Yankee 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. A scheduled refueling outage was completed in November 2008 and the next outage is scheduled for the spring of 2010. Our total VYNPC purchases were \$64 million in 2009, \$57.7 million in 2008 and \$55.8 million in 2007.

Prices under the PPA increase \$1 per megawatt-hour each calendar year, from \$43 in 2010 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. Estimated annual purchases are expected to be \$61 million for 2010, \$63 million for 2011 and \$16 million for 2012 when the contract expires in March. A summary of the PPA, including the actual amount for 2009 and the estimated average amounts through 2012, is 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.

	2009	**2010**	**Estimated Average 2011 - 2012**
Average capacity acquired	170 MW	178 MW	178 MW
Share of VYNPC entitlement	34.83%	34.83%	34.83%
Annual energy charge per mWh	\$42.05	\$43.05	\$44.26
Average total cost per mWh	\$41.22	\$43.43	\$45.37
Contract period termination			March 2012

We purchase replacement energy as needed when the Vermont Yankee plant is not operating or is operating at reduced levels. We typically acquire most of this replacement energy through forward purchase contracts and account for those contracts as derivatives.

In July 2008, the Vermont Yankee plant reduced production levels (also referred to as a "derate") for almost 12 days, reaching a low of approximately 17 to 20 percent capacity during some of that time. The derate was caused by issues related to the plant's cooling towers. The incremental costs of the replacement power that we purchased during that time amounted to approximately $1.1 million. We also lost approximately $1.1 million in resale sales revenue during that time. We were able to apply approximately $0.1 million as a reduction in purchased power expense from a regulatory liability established for the difference in the premium we paid for Vermont Yankee forced outage insurance and amounts collected in retail rates.

In the third quarter of 2007, the Vermont Yankee plant experienced a derate after the collapse of a cooling tower at the plant, and a two-day unplanned outage associated with a valve failure. We purchased replacement energy adequate to meet most of our hourly load obligations during that period. The derate and unplanned outage increased our net power costs by about $1.3 million in the third quarter of 2007 through increased purchased power expense and decreased operating revenues due to reduced resale sales. We were also able to apply $0.3 million as reduction in purchased power expense from the regulatory liability.

We are considering whether to seek recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the PPA based upon the results of certain reports, including an NRC inspection, in which the inspection team found that Entergy-Vermont Yankee, among other things, did not have sufficient design documentation available to help it prevent problems with the cooling towers. The NRC released its findings on October 14, 2008. In considering whether to seek recovery, we are also reviewing the 2007 and 2008 root cause analysis reports by Entergy and a December 22, 2008 reliability assessment provided by the Nuclear Safety Associates to the State of Vermont. We cannot predict the outcome of this matter at this time.

We have a forced outage insurance policy to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The current policy covers March 22, 2009 through March 21, 2010. This outage insurance does not apply to derates or acts of terrorism. The coverage applies to unplanned outages of up to 90 consecutive calendar days per outage event, and provides for payment of the difference between the hourly spot market price and $42/mWh. The aggregate maximum coverage is $9 million with a $1.2 million deductible. In October 2009, we purchased coverage for the period March 22, 2010 through March 21, 2011. The new policy has the same coverage terms as our current policy.

The PPA between Entergy-Vermont Yankee and VYNPC contains a formula for determining the VYNPC power entitlement following an uprate in 2006 that increased the plant's operating capacity by approximately 20 percent. VYNPC and Entergy-Vermont Yankee 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.

Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that we could lose this resource if the plant shuts down for any reason before that date. An early shutdown could cause our customers to lose economic benefit of an energy volume of 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 now available forward market prices as of December 31, 2009, the incremental replacement cost of lost power is estimated to average $27.5 million in 2010. 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 such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results if the costs are recovered in retail rates in a timely fashion.

Entergy-Vermont Yankee has submitted a renewal application with the NRC and an application for a Certificate of Public Good ("CPG") with the PSB for a 20-year extension of the Vermont Yankee plant operating license. Entergy-Vermont Yankee also needs approval from the PSB and Vermont Legislature to continue to operate beyond 2012. Significant hurdles may prevent its relicensing. Potential operating, transparency and communication issues related to the plant and its operations have raised serious concerns among regulators and members of the Vermont Legislature, including some who have called for its temporary or permanent shutdown. An intervenor in the CPG case has requested that the PSB order a shutdown of the Vermont Yankee plant pending resolution of current tritium leaks at the site. The PSB has opened a new docket to consider that request. We are unable to predict the outcome of this matter.

On February 24, 2010, in a non-binding vote, the Vermont Senate voted against allowing the PSB to consider granting the Vermont Yankee plant another 20-year operating license after 2012. A new Vermont legislature will be elected in the fall of 2010 and could vote differently. We are unable to predict the outcome of this matter.

At this time, Entergy-Vermont Yankee is attempting to overcome these concerns, but we have not held any formal negotiations on a new contract since these issues arose in January. We rejected Entergy-Vermont Yankee's current proposal, but both parties are prepared to resume negotiations for a purchased power contract when the issues that have emerged are resolved. We cannot predict the outcome at this time.

Hydro-Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. 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, altering 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. The average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015.

The annual load factor is 75 percent for the remainder of the VJO Power Contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described below.

There are two sellback contracts with provisions that apply to existing and future VJO Power Contract purchases. Two other sellback contracts, also negotiated in the early phase of the VJO Power Contract, have expired. The first sellback contract resulted in the sellback of 25 MW of capacity and associated energy through April 30, 2012, which has no net impact currently since an identical 25 MW purchase was made in conjunction with the sellback. We have a 23 MW share of the 25 MW sellback. However, since the sellback ends six months before the corresponding purchase ends, the first sellback will result in a 23 MW increase in our capacity and energy purchases for the period from May 1, 2012 through October 1, 2012.

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Quebec. The first option 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. To date, Hydro-Quebec has not 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.

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, 2009, our obligation is about 47 percent of the total VJO Power Contract through 2016, and represents approximately $352.1 million, on a nominal basis.

In accordance with FASB's guidance for guarantees, 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 an additional $412.7 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2010 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.

Total purchases from Hydro Quebec were $63.1 million in 2009, $63.7 million in 2008 and $64.9 million in 2007. Annual capacity costs decreased by $2.2 million starting November 1, 2009, which will continue for six contract years. A summary of the Hydro-Quebec actual charges for 2009 and the projected charges for the remainder of the contract are 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):

		Estimated Average	
	2009	2010 - 2013	2014 - 2016
Annual Capacity Acquired	**143.2**	145.5	(a)
Minimum Energy Purchase - annual load factor (b)	**75%**	75%	75%
Energy Charge	**$29,163**	$31,359	$20,313
Capacity Charge	**33,932**	32,420	19,869
Total Energy and Capacity Charge	**$63,095**	$63,779	$40,182
Average Cost per kWh	**$0.069**	$0.067	$0.070

(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 applies to 12-month periods beginning November 1. Calendar-year load factors may be different.

Independent Power Producers: We receive power from several Independent Power Producers ("IPPs"). These plants use water or biomass as fuel. Most of the power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Our total purchases from IPPs were $22.6 million in 2009, $26.4 million in 2008 and $22.8 million in 2007. Estimated annual purchases are expected to range from $9.9 million to $21.5 million for the years 2010 through 2014. Cost will begin to drop when a major contract obligation ends in 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	1.78%	1978	10.8
Joseph C. McNeil	Various	20.00%	1984	10.8
Millstone Unit #3	Nuclear	1.73%	1986	21.4
Highgate Transmission Facility		47.52%	1985	n/a

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

		2009			2008	
	Gross Investment	**Accumulated Depreciation**	**Net Investment**	Gross Investment	Accumulated Depreciation	Net Investment
Wyman #4	**$3,791**	**$3,018**	**$773**	$3,690	$2,914	$776
Joseph C. McNeil	**18,221**	**12,874**	**5,347**	15,857	12,291	3,566
Millstone Unit #3	**78,638**	**41,229**	**37,409**	77,879	40,246	37,633
Highgate Transmission Facility	**14,747**	**9,090**	**5,657**	14,489	8,731	5,758
	$115,397	**$66,211**	**$49,186**	$111,915	$64,182	$47,733

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.

We have a 1.7303 joint-ownership percentage in Millstone Unit #3, in which Dominion Nuclear Connecticut ("DNC") is the lead owner with 93.4707 percent of the plant joint-ownership. In August 2008 the NRC approved a request by DNC to increase the Millstone Unit #3 plant's generating capacity by approximately 7 percent. We are obligated to pay our ownership share of the related costs. The uprate was completed during the scheduled refueling outage that concluded in November 2008 and our share of plant generation increased by 1.4 MW.

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 the 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 commenced in May 2008. On October 15, 2008, the United States Court of Federal Claims issued a favorable decision in the case, including damages specific to Millstone Unit #3. The DOE appealed the court's decision in December 2008. On February 20, 2009, the government filed a motion seeking an indefinite stay of the briefing schedule. On March 18, 2009, the court granted the government's request to stay the appeal. On November 19, 2009, DNC filed a motion to lift the stay. The DOE opposed this motion and also asked the court to grant it an additional 45 days to file its initial brief in the appeal should the Court lift the stay. Once the stay is lifted, briefing on the appeal will take place. 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.

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 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 Nuclear Regulatory Commission ("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 and completely decommissioned except for the spent fuel storage at each location. Our obligations related to these plants are described in Part II, Item 8, 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. Changes in the underlying interest rates that affect the earnings and the liability could cause the balance to be a surplus or deficit. Excess funds, if any, will be returned to us and must be applied to the benefit of retail

Nuclear Insurance The Price-Anderson Act ("Act") provides a framework for immediate, no-fault insurance coverage for the public in the event of a nuclear power plant accident that is deemed an "extraordinary nuclear occurrence" by the NRC. The Energy Policy Act of 2005 reinstated and extended the Act for 20 years. There are 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 applies. For the second level, each nuclear plant must pay a retrospective premium 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 payout of $15 million per reactor. 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.

Performance Assurance We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $2.7 million with ISO-New England. We are required to post collateral for all net purchased power transactions in excess of this credit limit. 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.

At December 31, 2009, we had posted $5.4 million of collateral under performance assurance requirements for certain of our power contracts, all of which was represented by restricted cash. At December 31, 2008, we had posted $6.9 million of cash under performance assurance requirements for certain of our power contracts, of which $3.3 million was in cash and $3.6 million was represented by restricted cash.

We are also subject to performance assurance requirements under our Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If Entergy-Vermont Yankee, the seller, has commercially reasonable grounds to question our ability to pay for our monthly power purchases, Entergy-Vermont Yankee 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.

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. 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. These practices ended more than 50 years ago. 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.

The total reserve for environmental matters amounted to $1.6 million as of December 31, 2009 and $1.7 million as of December 31, 2008. Below is a brief discussion of the significant sites for which we have recorded reserves.

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 Vermont to develop a mutually acceptable solution. A corrective action plan was submitted to the State of Vermont on October 19, 2009 for their approval. We have reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it is adequate. The liability for site remediation is expected to range from $0.9 million to $2.3 million. As of December 31, 2009, we have accrued $1 million representing the most likely remaining 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. We have reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it is adequate. The liability for site remediation is expected to range from $0.1 million to $1.3 million. As December 31, 2009, we have accrued $0.5 million representing the most likely remaining 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. As of December 31, 2009, our remaining obligation was less than $0.1 million.

The reserve for environmental matters are included as current and long-term liabilities on the Consolidated Balance Sheets and 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.

In December 2009, we voluntarily submitted results of internally tested soil samples from two additional locations to the State of Vermont Sites Management Section ("SMS"). These soil sample results showed contamination at levels of concern to SMS. As a result, SMS has listed these sites as active hazardous waste sites and requested that we complete additional testing at these properties. Although management does not believe there is significant contamination at these sites, the extent and cost of potential remediation will not be known until the additional testing is completed during 2010.

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 $5.3 million at December 31, 2009 and $6.1 million at December 31, 2008. 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 FASB's guidance for leases. In accordance with FASB's guidance for regulated operations 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 $5.3 million, $5 million is related to the Phase II Hydro-Quebec ("Phase II") transmission facilities and the remaining $0.3 million is related to several five-year office and computing equipment leases.

We participated with other electric utilities in the construction of the 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 $31 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, 2009, the $5 million unamortized balance was comprised of $19.2 million related to our share of original costs and additional investments, offset by $14.2 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 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, 2009, 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 $3.2 million in 2010 to $2 million in 2016. If we elect to extend both agreements, annual payments are expected to increase during the renewal terms. Approximately $0.5 million of the annual costs are currently reimbursed to us pursuant to the New England Power Pool Open Access Transmission Tariff.

For the year ended December 31, 2009, imputed interest on capital leases totaled $0.5 million. A summary of minimum lease payments as of December 31, 2009 follows (dollars in thousands).

Year	Capital Leases
2010	$1,363
2011	1,250
2012	1,168
2013	1,083
2014	952
Thereafter	737
Future minimum lease payments	6,553
Less: amount representing interest	1,301
Present value of net minimum lease payments	$5,252

Operating Leases: Prior to October 24, 2008, we leased our vehicles and related equipment under a single operating lease agreement. The individual leases under this agreement were mutually cancelable one year from lease inception. On November 14, 2008, we received notification from the lessor that this operating lease agreement would be terminated. Under the terms of the lease, we were required to terminate all agreements under this lease before November 14, 2009 and pay the unamortized value of the equipment upon termination.

On October 30, 2009, we signed a vehicle lease agreement to finance many of the vehicles covered by this former agreement and the remaining vehicles were purchased from the leasing company. Our guarantee obligation under this lease will not exceed 8 percent of the acquisition cost. The maximum amount of future payments under this guarantee at December 31, 2009 is approximately $0.4 million. The total future minimum lease payments required for all lease schedules under this agreement at December 31, 2009 was $5.1 million. The maximum amount approved for lease under this agreement was $5.5 million, of which $5.4 million was outstanding at December 31, 2009.

On October 24, 2008, we entered into an operating lease for new vehicles and other related equipment leased after October 24, 2008. Our guarantee obligation under this lease is limited to 5 percent of the acquisition cost. The maximum amount of future payments under this guarantee is approximately $0.1 million. The total future minimum lease payments required for all lease schedules under this agreement at December 31, 2009 was $2.3 million. The maximum amount available for lease additions in 2010 under this agreement is $4.0 million. As of December 31, 2009 the total acquisition cost of all lease additions under this lease was approximately $2.6 million. At December 31, 2008, the maximum amount available for lease under this agreement was $4 million, of which $2.3 million was outstanding.

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, 2009, future minimum rental payments required under non-cancelable operating leases are expected to total $7.0 million, consisting of $1.8 million in 2010 and 2011, $1.3 million in 2012, $1.1 million in 2013, $0.7 million in 2014 and $0.3 million thereafter.

Total rental expense, which includes pole attachment rents in addition to the operating lease agreements described above, amounted to $6.3 million in 2009, $6.3 million in 2008 and $6.8 million in 2007. These are included in Other operation on the Consolidated Statements of Income.

Reserve for Loss on Power Contract In 2005, we established a reserve for a loss on a terminated power sales agreement in connection with the sale of a subsidiary's franchise. The reserve is being amortized on a straight-line basis through 2015 as the cash is paid out under the underlying supply contracts. The amortization is being credited to purchase power expense on the Consolidated Statement of Income. The balance of the reserve was $7.2 million at December 31, 2009 and $8.4 million at December 31, 2008. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets.

Customer Bankruptcy On October 26, 2009, a major telecommunications customer filed for bankruptcy protection. In 2009, this customer received electric services totaling $2.1 million and as of December 31, 2009, our accounts receivable includes an estimate of the net realizable amount. We are unable to predict the outcome of this matter at this time or its impact on our financial statements.

Catamount Indemnifications On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). 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 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 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, 2009 and 2008.

NOTE 18 - SEGMENT REPORTING

Our reportable operating segments include: **Central Vermont Public Service Corporation ("CV - VT")**, represents our principal utility operations, 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** represents our non-utility operations and consists of 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 Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies. All segment operations are managed centrally by CV - VT. 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. Inter-segment revenues are excluded from the table below and are $0.3 million in 2009 and 2008 and less than $0.1 million for 2007. Financial information follows (dollars in thousands):

2009	CV VT	Other Companies	Reclassification and Consolidating Entries	Consolidated
Revenues from external customers	**$342,098**	**$1,731**	**($1,731)**	**$342,098**
Depreciation and amortization (a)	**$17,070**	**$214**	**($214)**	**$17,070**
Operating income tax expense	**$5,033**	**$303**	**($303)**	**$5,033**
Equity in earnings of affiliates	**$17,472**	**$0**	**$0**	**$17,472**
Interest income (b)	**$99**	**($22)**	**$0**	**$77**
Interest expense	**$11,600**	**($118)**	**$0**	**$11,482**
Net income	**$19,908**	**$841**	**$0**	**$20,749**
Investments in affiliates	**$129,733**	**$0**	**$0**	**$129,733**
Total assets	**$630,103**	**$2,356**	**($307)**	**$632,152**
Construction and plant expenditures (c)	**$31,413**	**$386**	**$0**	**$31,799**
2008				
Revenues from external customers	$342,162	$1,751	($1,751)	$342,162
Depreciation and amortization (a)	$11,862	$192	($192)	$11,862
Operating income tax expense	$4,878	$473	($473)	$4,878
Equity in earnings of affiliates	$16,264	$0	$0	$16,264
Interest income (b)	$406	$24	($24)	$406
Interest expense	$11,568	$51	($51)	$11,568
Net income	$16,168	$217	$0	$16,385
Investments in affiliates	$102,232	$0	$0	$102,232
Total assets	$624,341	$3,184	($1,399)	$626,126
Construction and plant expenditures (c)	$36,835	$339	$0	$37,174

2007				
Revenues from external customers	$329,107	$1,798	($1,798)	$329,107
Depreciation and amortization (a)	$10,993	$184	($184)	$10,993
Operating income tax (benefit) expense	$5,291	$329	($329)	$5,291
Equity in earnings of affiliates	$6,430	$0	$0	$6,430
Interest income (b)	$587	$58	$0	$645
Interest expense	$8,475	$47	$0	$8,522
Net income	$15,317	$487	$0	$15,804
Investments in affiliates	$93,452	$0	$0	$93,452
Total assets	$538,481	$2,134	($301)	$540,314
Construction and plant expenditures (c)	$23,663	$250	$0	$23,913

(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.

NOTE 19 - 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)
2009					
Operating revenues	**$90,727**	**$82,627**	**$81,791**	**$86,953**	**$342,098**
Utility operating income	**$6,623**	**$4,763**	**$5,216**	**$2,286**	**$18,888**
Net income	**$6,872**	**$5,497**	**$6,200**	**$2,180**	**$20,749**
Basic earnings per share	**$0.58**	**$0.46**	**$0.52**	**$0.18**	**$1.75**
Diluted earnings per share	**$0.58**	**$0.46**	**$0.52**	**$0.18**	**$1.74**
2008					
Operating revenues	$91,224	$84,487	$83,767	$82,684	$342,162
Utility operating income	$6,432	$4,243	$7,315	$440	$18,430
Net income	$5,908	$4,001	$6,481	($5)	$16,385
Basic earnings per share	$0.57	$0.38	$0.62	($0.01)	$1.53
Diluted earnings per share	$0.56	$0.38	$0.61	($0.01)	$1.52

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

NOTE 20 - SUBSEQUENT EVENTS

On March 11, 2010, we signed a memorandum of understanding ("MOU") with Green Mountain Power and Hydro-Quebec ("Parties") that sets the stage for a new power supply contract. Under the terms of the MOU, Vermont utilities will be eligible to purchase up to 225 megawatts starting in November 2012 and ending in 2038. We will seek to purchase volumes similar to what we currently purchase from Hydro-Quebec. There is a price-smoothing mechanism that will shield customers from volatile market price spikes over the life of the contract.

The MOU commits the parties to negotiate in good faith a power purchase agreement based on a non-binding term sheet. The parties intend to negotiate the material terms of the power purchase agreement no later than June 30, 2010, to allow the parties to obtain all necessary internal organizational approvals and execute the agreement no later than July 31, 2010. The final agreement will be subject to PSB approval. Should the parties fail to execute an agreement for any reason prior to July 31, 2010, the MOU and the obligations of the parties to negotiate a final agreement will terminate.

<u>Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</u>
None

<u>Item 9A. Controls and Procedures</u>
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, 2009. Based on this evaluation, our Chief Executive Officer and Principal Financial and Accounting Officer concluded that, as of December 31, 2009, 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, 2009.

The effectiveness of our internal control over financial reporting 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 was one material change to our internal control over financial reporting that occurred during the quarter ended March 31, 2009. Effective January 1, 2009, we implemented several SAP enterprise resource planning ("ERP") modules, including general ledger, consolidation, accounts payable, supply chain, fixed assets (property accounting), treasury, payroll and human resources. The implementation of these ERP modules and the related workflow capabilities resulted in a material change to our internal controls over financial reporting (as defined in Rules 13(a)-15(f) or 15(d)-15(f) under the Exchange Act). As a result, we modified the design and documentation of internal control processes and procedures relating to the new system to replace and supplement existing internal controls over financial reporting, as appropriate. Specifically, we modified controls in the business processes impacted by the new system, such as user access security, system reporting and authorization and reconciliation procedures. The system change was undertaken to integrate systems and consolidate information, and was not undertaken in response to any actual or perceived deficiencies in our internal controls over financial reporting.

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2009 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, 2009, 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, 2009, 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, 2009 of the Company and our report dated March 12, 2010, which report expresses an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule and refers to the reports of other auditors (which as to Velco included an explanatory paragraph concerning a change in accounting for non-controlling interests).

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 12, 2010

Item 9B. Other Information

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 2010 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 25, 2010.

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 2010 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010.

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 2010 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010. The Equity Compensation Plan Information is shown in the table below.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
1997 Stock Option Plan for Key Employees	43,298	$20.48	-
2000 Stock Option Plan for Key Employees	182,630	$16.49	-
Omnibus Stock Plan	109,369	$20.27	132,740
Total	**335,297**	**$18.24**	**132,740**

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 2010 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010.

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 2010 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(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 By-laws

3-1 By-laws, as amended February 9, 2010. (Exhibit 99.2, Current Report on Form 8-K Filed February 16, 2010, 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)

3-2.1 Articles of Association, as amended February 17, 2010. (Exhibit No. 3-2.1, Current Report on Form 8-K Filed February 16, 2010, 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)

4-7 Forty-Sixth Supplemental Indenture, dated as of May 1, 2008, from the Company to U.S. Bank National Association, as trustee. (Exhibit 4-7, Current Report on Form 8-K Filed May 15, 2008, File No. 1-8222)

4-8 Bond Purchase Agreement, dated as of May 15, 2008, among the Company and the purchasers listed on Schedule A thereto. (Exhibit 4-8, Current Report on Form 8-K Filed May 15, 2008, 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, 1961, 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 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)

10.7 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 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)

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

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

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

10.12 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)

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

10.12.2 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)

10.13 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)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10.14.27 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)

10.14.28 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)

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

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

10.15.2 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)

10.15.3 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)

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

10.16 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)

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

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

10.17 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)

10.18 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)

10.18.1 Revision dated April 1, 1975. (Exhibit C-61, 1981 Form 10-K, File No. 1-8222)

10.18.2 Amendment dated May 6, 1988. (Exhibit 10-181, 1988 Form 10-K, File No. 1-8222)

10.18.3 Amendment dated June 26, 1989. (Exhibit 10-196, 1989 Form 10-K, File No. 1-8222)

10.18.4 Amendment dated July 1, 1989. (Exhibit 10-197, 1989 Form 10-K, File No. 1-8222)

10.18.5 Amendment dated February 1, 1992 (Exhibit 10.25.5, 1992 Form 10-K, File No. 1-8222)

10.18.6 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)

10.18.7 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)

10.18.8 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)

10.18.9 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)

10.18.10 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)

10.19 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)

10.20 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)

10.20.1 Supplementary Power Contract dated March 1, 1978. (Exhibit C-94, 1982 Form 10-K, File No. 1-8222)

10.20.2 Amendment dated August 22, 1980. (Exhibit C-95, 1982 Form 10-K, File No. 1-8222)

10.20.3 Amendment dated October 15, 1982. (Exhibit C-96, 1982 Form 10-K, File No. 1-8222)

10.20.4 Second Supplementary Power Contract dated April 30, 1984. (Exhibit C-115, 1984 Form 10-K, File No. 1-8222)

10.20.5 Additional Power Contract dated April 30, 1984. (Exhibit C-116, 1984 Form 10-K, File No. 1-8222)

10.20.6 1987 Supplementary Power Contract, dated as of April 1, 1987. (Exhibit 10.27.6, Form 10-Q, June 30, 2000, File No. 1-8222)

10.20.7 1996 Amendatory Agreement, dated December 1, 1996. (Exhibit 10.27.7, Form 10-Q, June 30, 2000, File No. 1-8222)

10.20.8 2000 Amendatory Agreement, dated May, 2000. (Exhibit 10.27.8, Form 10-Q, June 30, 2000, File No. 1-8222)

10.21 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)

10.22 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)

10.22.1 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)

10.23 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)

10.24 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)

10.25 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)

10.26 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)

10.26.1 Amendment dated June 1, 1982. (Exhibit C-98, 1982 Form 10-K, File No. 1-8222)

10.27 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)

10.27.1 Amendment No. 1 dated January 1, 1986. (Exhibit C-132, 1986 Form 10-K, File No. 1-8222)

10.28 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)

10.29 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)

10.29.1 Amendment No. 3 dated January 1, 1986. (Exhibit 10-149, 1986 Form 10-K, File No. 1-8222)

10.30 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)

10.31 Power Purchase Agreement between Velco and CVPS dated June 1, 1981. (Exhibit C-103, 1982 Form 10-K, File No. 1-8222)

10.32 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)

10.32.1 Amendment No. 1 dated October 5, 1982. (Exhibit C-108, 1983 Form 10-K, File No. 1-8222)

10.32.2 Amendment No. 2 dated December 30, 1983. (Exhibit C-109, 1983 Form 10-K, File No. 1-8222)

10.32.3 Amendment No. 3 dated January 10, 1984. (Exhibit 10-143, 1986 Form 10-K, File No. 1-8222)

10.33 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)

10.34 Copy of Highgate Transmission Interconnection Preliminary Support Agreement dated April 9, 1984. (Exhibit C-117, 1984 Form 10-K, File No. 1-8222)

10.35 Copy of Allocation Contract for Hydro-Quebec Firm Power dated July 25, 1984. (Exhibit C-118, 1984 Form 10-K, File No. 1-8222)

10.35.1 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)

10.36 Copy of Highgate Operating and Management Agreement dated August 1, 1984. (Exhibit C-119, 1986 Form 10-K, File No. 1-8222)

10.36.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-152, 1986 Form 10-K, File No. 1-8222)

10.36.2 Amendment No. 2 dated November 13, 1986. (Exhibit 10-167, 1987 Form 10-K, File No. 1-8222)

10.36.3 Amendment No. 3 dated January 1, 1987. (Exhibit 10-168, 1987 Form 10-K, File No. 1-8222)

10.36.4 Amendment No. 4 dated December 1, 2008.

10.37 Copy of Highgate Construction Agreement dated August 1, 1984. (Exhibit C-120, 1984 Form 10-K, File No. 1-8222)

10.37.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-151, 1986 Form 10-K, File No. 1-8222)

10.38 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)

10.38.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-153, 1986 Form 10-K, File No. 1-8222)

10.38.2 Amendment No. 2 dated April 18, 1985. (Exhibit 10-154, 1986 Form 10-K, File No. 1-8222)

10.38.3 Amendment No. 3 dated February 12, 1986. (Exhibit 10-155, 1986 Form 10-K, File No. 1-8222)

10.38.4 Amendment No. 4 dated November 13, 1986. (Exhibit 10-169, 1987 Form 10-K, File No. 1-8222)

10.38.5 Amendment No. 5 and Restatement of Agreement dated January 1, 1987. (Exhibit 10-170, 1987 Form 10-K, File No. 1-8222)

10.39 Copy of the Highgate Transmission Agreement dated August 1, 1984. (Exhibit C-122, 1984 Form 10-K, File No. 1-8222)

10.40 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)

10.40.1 First Amendment dated March 1, 1985. (Exhibit C-127, 1985 Form 10-K, File No. 1-8222)

10.41 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)

10.42 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)

10.43 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)

10.44 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)

10.44.1 Amendment dated February 1, 1987. (Exhibit 10-171, 1987 Form 10-K, File No. 1-8222)

10.45 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)

10.45.1 Amendment No. 1 dated September 28, 1988. (Exhibit 10-182, 1988 Form 10-K, File No. 1-8222)

10.45.2 Amendment No. 2 dated October 1, 1991. (Exhibit 10.56.2, 1991 Form 10-K, File No. 1-8222)

10.45.3 Amendment No. 3 dated December 31, 1994. (Exhibit 10.56.3, 1994 Form 10-K, File No. 1-8222)

10.45.4 Amendment No. 4 dated December 31, 1996. (Exhibit 10.56.4, 1996 Form 10-K, file No. 1-8222)

10.46 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)

10.46.1 Amendment No. 1 dated September 22, 1985. (Exhibit 10-157, 1986 Form 10-K, File No. 1-8222)

10.47 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)

10.47.1 Amendment No. 1 dated June 20, 1986. (Exhibit 10-159, 1986 Form 10-K, File No. 1-8222)

10.48 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)

10.48.1 Amendment No. 17 dated November 25, 1985. (Exhibit 10-162, 1986 Form 10-K, File No. 1-8222)

10.49 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)

10.50 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)

10.50.1 Amendment dated September 1, 1993 (Exhibit 10.63.1, 1993 Form 10-K, File No. 1-8222)

10.51 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)

10.51.1 Amendment No. 1 dated August 31, 1988. (Exhibit 10-191, 1988 Form 10-K, File No. 1-8222)

10.51.2 Amendment No. 2 dated September 19, 1990. (Exhibit 10-202, 1990 Form 10-K, File No. 1-8222)

10.51.3 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)

10.51.4 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)

10.52 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)

10.52.1 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)

10.53 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)

10.54 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)

10.55 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)

10.56 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)

10.56.1 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)

10.57 Operating Agreement of Vermont Transco, LLC effective July 1, 2006. (Exhibit 10.94, 2006 Form 10-K, File No. 1-8222)

10.58 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)

10.59 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)

10.60 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)

10.61 Credit Agreement dated as of November 3, 2008 between Central Vermont Public Service Corporation, as Borrower and KeyBank National Association, as Lender. (Exhibit 10.98, Current Report on Form 8-K Filed November 7, 2008, File No. 1-8222)

10.62 Memorandum of Understanding, dated December 17, 2008, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.99, Current Report on Form 8-K Filed December 18, 2008, File No. 1-8222)

10.63 Agreement between Central Vermont Public Service Corporation and Local Union No. 300 International Brotherhood of Electrical Workers Effective as of January 1, 2009. (Exhibit 10.100, Current Report on Form 8-K Filed January 7, 2009, 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 August 4, 2008, With an Effective Dated of January 1, 2008. (Exhibit A 10.3.1, Form 10-Q, June 30, 2008, 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 Form of Change In Control Agreement to Become Effective April 2009. (Exhibit A 10.5.2, Form 10-Q, March 31, 2008, 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 August 4, 2008, With An Effective Date of January 1, 2005. (Exhibit A 10.7.1, Form 10-Q, June 30, 2008, File No. 1-8222)

A 10.8 Omnibus Stock Plan (Amended and Restated 2002 Long-Term Incentive Plan). (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 28, 2008, File No. 1-8222)

A 10.9 Performance Share Incentive Plan, Effective January 1, 2008. (Exhibit A 10.11, 2007 Form 10-K, File No. 1-8222)

A 10.10 Performance Share Incentive Plan, Effective January 1, 2009. (Exhibit A 10.18, Current Report on Form 8-K Filed May 11, 2009, File No. 1-8222)

A 10.11 Performance Share Incentive Plan, Effective January 1, 2010. (Exhibit A 10.17, Current Report on Form 8-K Filed March 5, 2010, File No. 1-8222)

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 Management Incentive Plan, Effective as of January 1, 2010. (Exhibit A 10.16, Current Report on Form 8-K Filed March 5, 2010, File No. 1-8222)

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 Consent of Independent Registered Public Accounting Firm (KPMG - VELCO)

* 23.3 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 Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

* 31.2 Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

* 32.1 Certification of Principal 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 Principal 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 Electric Power Company, Inc. and Subsidiary

* 99.2 Financial Statements of Vermont Transco LLC.

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* 99.1 Financial Statements of Vermont Electric Power Company, Inc. and Subsidiary

* 99.2 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
2009							
Reserves deducted from assets to which they apply:							
			$107,521	(1)			
			$500,777	(2)			
			$222,754	(4)			
Reserve for uncollectible accounts receivable	$2,183,600	3,078,816	$831,052		$2,516,241	(3)	$3,577,227
Reserves shown separately:							
Environmental Reserve	$1,731,551				$166,171		$1,565,380
2008							
Reserves deducted from assets to which they apply:							
			$112,413	(1)			
			$474,398	(2)			
Reserve for uncollectible accounts receivable	$1,751,069	$2,472,997	$586,811		$2,627,277	(3)	$2,183,600
Reserve for uncollectible accounts receivable - affiliates	$47,848				$47,848		$0
Reserves shown separately:							
Environmental Reserve	$1,917,674				$186,123		$1,731,551
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	(3)	$1,751,069
Reserve for uncollectible accounts receivable - affiliates	$47,848						$47,848
Reserves shown separately:							
Environmental Reserve	$2,076,282				$158,608		$1,917,674

Notes:

(1) Amount collected from collection agencies

(2) Collections of accounts previously written off

(3) Uncollectible accounts written off

(4) Amounts charged directly to income

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
Senior Vice President, Chief Financial Officer, and Treasurer

March 15, 2010

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 15, 2010.

Signature	Title
Robert H. Young*	President and Chief Executive Officer, and Chair of the Board of Directors (Principal Executive Officer)
/s/ Pamela J. Keefe (Pamela J. Keefe)	Senior Vice President, Chief Financial Officer, and Treasurer (Principal Financial and Accounting Officer)
William R. Sayre*	Lead Director
Robert L. Barnett*	Director
Robert G. Clarke*	Director
John M. Goodrich*	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.