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, 2010

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	03-0111290
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**
77 Grove Street, Rutland, Vermont	05701
(Address of principal executive offices)	**(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 Website, 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 (Do not check if a smaller reporting company)	☐	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, 2010 (2nd quarter) was approximately $200,209,614 (based on the $19.74 per share closing price of the Company's Common Stock, $6 Par Value, as reported on the New York Stock Exchange on June 30, 2010). 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, 2010, 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 28, 2011 there were outstanding 13,361,029 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 3, 2011 to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Act of 1934, is incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
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GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found in the report:

Current or former CVPS Companies, Segments or Investments

CRC	Catamount Resources Corporation
Custom	Custom Investment Corporation
CV or CVPS	Central Vermont Public Service Corporation
East Barnet	Central Vermont Public Service Corporation - East Barnet Hydroelectric, Inc.
Transco	Vermont Transco LLC
VELCO	Vermont Electric Power Company, Inc.
VETCO	Vermont Electric Transmission Company, Inc.
VYNPC	Vermont Yankee Nuclear Power Corporation

Regulatory and Other Authorities

DOE	United States Department of Energy
DPS	Vermont Department of Public Service
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NRC	Nuclear Regulatory Commission
PSB	Vermont Public Service Board
SEC	Securities and Exchange Commission
VANR	Vermont Agency of Natural Resources

Other

AFUDC	Allowance for funds used during construction
AOCL	Accumulated other comprehensive loss
ARP MOU	Memorandum of Understanding with the DPS on the Alternative Regulation II Plan
ARRA	American Recovery and Reinvestment Act
CDA	Connecticut Development Authority Bonds
Connecticut Yankee	Connecticut Yankee Atomic Power Company
CVPS SmartPower™	CV's "smart grid" program designed to modernize and automate the electrical grid, provide automated meter reading, and empower consumers to make better energy choices. The plan includes two-way communications systems and strategies to introduce new rate designs, including dynamic pricing and demand response programs.
CVPS SmartPower™ MOU	Memorandum of Understanding with the DPS on CVPS SmartPower™
DNC	Dominion Nuclear Connecticut
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DUP	Vermont's Distributed Utility Planning
EEI	Edison Electric Institute
EEU	Vermont Energy Efficiency Utility
Entergy-Vermont Yankee	Entergy Nuclear Vermont Yankee, LLC
EPACT	Federal Energy Policy Act of 2005
EPS	Earnings per share
ERM	Enterprise Risk Management
ESAM	Earnings sharing adjustment mechanism
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FTRs	Financial Transmission Rights
GMP	Green Mountain Power Corporation

HQUS PPA	Long-term power purchase and sale agreement with H.Q. Energy Services (U.S) Inc.
IASB	International Accounting Standards Board
IFRS	International financial reporting standards
IPPs	Independent Power Producers
ISO-NE	New England Independent System Operator
kWh	Kilowatt-hours
Maine Yankee	Maine Yankee Atomic Power Company
Moody's	Moody's Investors Service
MOU	Memorandum of Understanding
MW	Megawatt
MWh	Megawatt-hours
NOATT	NEPOOL Open Access Transmission Tariff
NYSE	New York Stock Exchange
OASIS	Open Access Same-time Information System
Omnibus Stock Plan	Central Vermont Public Service Corporation Omnibus Stock Plan
PCAM	Power supply and transmission-by-others cost adjustment mechanism
PCB	Polychlorinated biphenyl contamination
Pension Plan	A qualified, non-contributory, defined-benefit pension plan
Phase I	Hydro-Québec Phase I
Phase II	Hydro-Québec Phase II
PPA	Purchased power contract
PPACA	The Federal Patient Protection and Affordable Care Act
PSNH	Public Service Company of New Hampshire
PTF	Pool Transmission Facility
Readsboro	Readsboro Electric Department
ROA	Return on Assets
ROE	Return on Equity
RTO	Regional Transmission Organization
SERP	Officers' Supplemental Retirement Plan
SMD	Standard Market Design
SPEED	Sustainably Priced Energy Development Program for Vermont Utilities
Staffing MOU	Memorandum of Understanding with the DPS to review staffing level
TbyO	Transmission by Others costs
The Exchange Act	Securities and Exchange Act of 1934
TPH	Total petroleum hydrocarbons
TSR	Total Shareholder Return
U.S. GAAP	Generally Accepted Accounting Principles in the United States of America
VEDA	Vermont Economic Development Authority
Vermont Marble	Vermont Marble Power Division of Omya Industries, Inc.
VIDA	Vermont Industrial Development Authority Bonds
VJO	Vermont Joint Owners
VPPSA	Vermont Public Power Supply Authority
VTA	Vermont Transmission Agreement (1991)
VY PPA	Purchased power contract between VYNPC and Entergy-Vermont Yankee
Yankee Atomic	Yankee Atomic Electric Company

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 requirements;
- the 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-NE;
- 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;
- the performance of other parties in joint projects, including other Vermont utilities, state entities 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. A more detailed assessment of the risks that could cause actual results to materially differ from current expectations is contained in Part I, Item 1A, Risk Factors.

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-NE, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue from these sales helps to mitigate our power supply costs.

Our wholly owned subsidiaries include:

- 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.
- East Barnet, 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.
- CRC was formed to hold our investments in unregulated business opportunities. CRC's wholly owned subsidiary, SmartEnergy Water Heating Services, Inc., engages in the sale and rental of electric water heaters in Vermont and New Hampshire. On December 9, 2010, we dissolved CRC's wholly owned subsidiary, Eversant Corporation, the former parent of SmartEnergy Water Heating Services, Inc. There was no impact on our financial statements or results of operations.
- Custom was formed for the purpose of holding passive investments, including the stock of our subsidiaries that invest in regulated business opportunities. On October 13, 2003, we transferred our shares of VYNPC to Custom. The transfer to Custom did not affect our rights and obligations related to VYNPC. On December 30, 2009, Custom transferred the VYNPC shares back to us and in the third quarter of 2010, Custom was dissolved. There was no impact on our financial statements or results of operations.

Our equity ownership interests as of December 31, 2010 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-Vermont Yankee. The sale agreement included a purchased power contract between VYNPC and Entergy-Vermont Yankee. Under the VY PPA, 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 VELCO. In June 2006, VELCO transferred substantially all of its business operations and assets to Transco. VELCO's wholly owned subsidiary, VETCO, 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 36.68 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 9.23 percent of the voting equity units of Transco. Our total direct and indirect (through our VELCO ownership) interest in Transco is 41.02 percent of the voting equity units.
- We own 2 percent of the outstanding common stock of Maine Yankee, 2 percent of the outstanding common stock of Connecticut Yankee and 3.5 percent of the outstanding common stock of 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 21 - 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 remained essentially flat, with 2010 sales being higher than 2000 sales by 1.6 million kWh, or less than 1 percent. Annual changes between 2000 and 2010 ranged from a decrease of more than 3 percent in 2009 to increases of more than 2 percent in 2004 and 2005, mainly resulting from economic conditions.

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 2010 and 2009 and about 6 percent in 2008. Resale sales are comprised of long-term sales to third parties in New England, sales in the energy markets administered by ISO-NE and short-term system capacity sales. Operating revenues as of December 31 consisted of the following:

	Revenues			**Energy (MWh) Sales**		
	2010	2009	2008	**2010**	2009	2008
Retail Sales:						
Residential	**43%**	41%	40%	**33%**	33%	33%
Commercial	**32%**	30%	32%	**28%**	27%	29%
Industrial and other	**11%**	10%	11%	**13%**	12%	13%
Resale Sales	**11%**	16%	14%	**26%**	28%	25%
Other operating revenue	**3%**	3%	3%	**0%**	0%	0%

Retail Rates: Our retail rates are set by the PSB after considering the recommendations of Vermont's consumer advocate, the 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 9 - Retail Rates and Regulatory Accounting.

Wholesale Rates: We provide wholesale transmission service to nine network customers and four point-to-point customers under ISO-NE 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-NE 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, 2010 energy generation and purchased power required to serve retail customers totaled 2,359,000 MWh. The maximum one-hour integrated demand during that period was 406.1 MW and occurred on July 8, 2010. For 2009, our energy generation and purchased power required to serve retail customers totaled 2,316,000 MWh. The maximum one-hour integrated demand was 407.4 MW and occurred on December 29, 2009. The sources of energy and capacity available to us for the year ended December 31, 2010 are as follows:

	Net Effective Capability	Generated and Purchased	
	12 Month Average MW	mWh	Percent
Wholly Owned Plants:			
Hydro	35.8	207,779	6.6
Diesel and Gas Turbine	22.2	591	0.0
Jointly Owned Plants:			
Millstone #3	21.4	161,536	5.2
Wyman #4	10.8	2,174	0.1
McNeil	10.5	54,440	1.7
Long-Term Purchases:			
VYNPC	180.3	1,384,551	44.1
Hydro-Quebec	132.9	963,027	30.6
Independent power producers	26.5	195,325	6.2
Other Purchases:			
System and other purchases	32.2	51,428	1.6
NEPOOL (ISO-New England)	43.5	122,801	3.9
Total	516.1	3,143,652	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-Québec 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-Québec 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 will be $44 in 2011 and $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. For additional information regarding VYNPC see Part II, Item 8, Note 4 - Investment in Affiliates and Note 19 - Commitments and Contingencies - Long-term Power Purchases.

Hydro-Québec: We purchase power from Hydro-Québec under the 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-Québec that altered the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO power 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. For additional information see Part II, Item 8, Note 19 - Commitments and Contingencies - Long-term Power Purchases.

New Hydro-Québec Agreement: On August 12, 2010 we, along with GMP, VPPSA, Vermont Electric Cooperative, Vermont Marble, Town of Stowe Electric Department, City of Burlington, Vermont Electric Department, Washington Electric Cooperative, Inc. and the 13 municipal members of VPPSA (collectively, the "Buyers") entered into an agreement for the purchase of shares of 218 MW to 225 MW of energy and environmental attributes from HQUS commencing on November 1, 2012 and continuing through 2038.

The HQUS PPA will replace approximately 65 percent of the existing VJO power contract discussed above which, along with the VY PPA, supply the majority of Vermont's current power needs. The VJO power contract and the VY PPA expire within the next several years. See Part II, Item 8, Note 19 - Commitments and Contingencies - Long-term Power Purchases.

Independent Power Producers: We purchase power from several 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-NE: We participate in the New England regional wholesale electric power markets operated by ISO-NE, the regional bulk power transmission organization established to assure reliable and economical power supply in New England, which is governed by the 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-NE's settlement process to balance our resource output and load requirements.

See Part II, Item 8, Note 19 - Commitments and Contingencies for additional information related to our 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 rates 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 within their boundaries. 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 as a result of 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 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 19 - Commitments and Contingencies - Environmental.

Competitive Conditions Competition can be observed from a few different perspectives. At the wholesale level, New England implemented SMD in 2003. SMD is a competitive, location-based market pricing framework that has resulted in competition between power suppliers in lieu of regulated cost-of-service pricing. Similar versions of SMD have been implemented in the other parts of the New York and Eastern Interconnection grid.

In the broader context of energy services as a market sector, electricity and fossil fuels compete primarily for heat and industrial processes. However, the recent entry of electric vehicles into the market could, over time, expand the field of competition to the transportation sector as well. Competitive considerations between electricity and fossil fuels include cost, efficiency, service quality, convenience, environmental considerations, availability and safety.

Many of these same factors are expected to influence demand in the large commercial and industrial sectors as well. Cogeneration, self-generation and demand side management programs can be competitive threats to network electric sales by displacing electric demand within a utility's franchise territory and reducing the customer base over which utility costs are spread.

In the near-term, demand growth in the state is expected to be slow, or possibly negative, due to improvements in appliance efficiency standards, slow economic recovery and Vermont's energy efficiency programs. In the longer term, we expect the emergence of new hyper-efficient space and water heating technologies, the use of electricity as a transportation energy source, CVPS SmartPower™ pricing programs and carbon gas regulation may increase the pace of growth in electricity demand.

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 and our production units. In 2010, capital expenditures were $33 million.

Capital expenditures for the years 2011 to 2015 are expected to range from $36 million to $60 million annually, including an estimated total of more than $60 million for CVPS SmartPower™ over the five-year period. A portion of this CVPS SmartPower™ project total will be funded by the Smart Grid Stimulus Grant and this grant has reduced the 2011 to 2015 annual spending range above. Further discussion of the Smart Grid Stimulus Grant can be found in Part II, Item 8, Retail Rates and Regulatory Accounting - CVPS SmartPower™.

Number of Employees At December 31, 2010, we had 517 employees. Of these employees, 206 were represented by Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers. 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, the number of employees has been reduced in anticipation of CVPS SmartPower™ operational efficiencies and for other reasons.

Executive Officers of Registrant The following are the executive officers. There are no family relationships among the executive officers. Officers are normally elected annually and serve for one year or until a successor is elected.

Name and Age	**Office**	**Officer Since**
Robert H. Young, 63	Executive Chairman (effective March 1, 2011)	1987
Lawrence J. Reilly, 55	President and chief executive officer (effective March 1, 2011)	2011
Pamela J. Keefe, 45	Senior vice president, chief financial officer, and treasurer	2006
William J. Deehan, 58	Vice president - power planning and regulatory affairs	1991
Joan F. Gamble, 53	Vice president - strategic change and business services	1998
Brian P. Keefe, 53	Vice president - government and public affairs	2006
Joseph M. Kraus, 55	Senior vice president - operations, engineering and customer service	1987
Dale A. Rocheleau, 52	Senior vice president, general counsel and corporate secretary	2003

Mr. Young joined the company in 1987. Prior to being elected to his present position he served as president and CEO from 1995 to March 2011. Mr. Young also serves as president, CEO, and chair of our subsidiaries: East Barnet; C. V. Realty, Inc.; CRC; 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 VETCO. 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.

On February 14, 2011, Lawrence J. Reilly was appointed to serve as chief executive officer and president of the company effective March 1, 2011. Mr. Young became executive chairman and will remain on the board of directors and serve as principal executive officer until his previously announced planned retirement on May 3, 2011.

Mr. Reilly joined the company in March 2011. Prior to joining the company, since July 2008, Mr. Reilly has provided energy consulting services independently. He has assisted utilities and regulators in the nation of Jordan under a contract funded by the U.S. Agency for International Development; served as an advisor to GroundedPower, a startup smart grid company; and consulted for NuGen Capital Management LLC, which develops, installs and owns large-scale (1 to 10 megawatt) rooftop and ground-mount solar systems. He also serves as vice chair of the Massachusetts Technology Collaborative, a quasi-public entity that fosters a more favorable environment for the formation, retention and expansion of technology-related enterprises in Massachusetts. Mr. Reilly served National Grid USA and various subsidiaries from 1982 to 2008 in a succession of positions of increasing responsibility. Mr. Reilly began as an attorney at New England Electric System (NEES) in Westborough, Mass., and later served as counsel at its Rhode Island subsidiary, Narragansett Electric, from 1987 to 1990; vice president and director of rates at NEES from 1990 to 1996; president of the NEES electric distribution companies in Massachusetts, Rhode Island and New Hampshire from 1996 to 2001; executive vice president and general counsel of National Grid USA from 2001 to 2007 following United Kingdom-based National Grid Plc's acquisition of NEES; and executive vice president, legal and regulation, at National Grid in 2007 and 2008. Mr. Reilly is a director of the Samuel Huntington Foundation and a member of the Board of Overseers of the Rhode Island Philharmonic Orchestra.

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, senior vice president, chief financial officer, and treasurer of our subsidiaries: East Barnet; C.V. Realty, Inc.; CRC; 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. She serves as a director for our subsidiary SmartEnergy Water Heating Services, Inc. She is also on the board of the Vermont Achievement Center, Rutland Regional Medical Center, and Rutland Regional Health Service.

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.

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: East Barnet; C.V. Realty, Inc.; CRC; and SmartEnergy Water Heating Services, Inc. Additionally, Mr. Kraus serves as a director and officer 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: East Barnet; C.V. Realty, Inc.; CRC; and SmartEnergy Water Heating Services, Inc. He is also a trustee of the University of Vermont Board of Trustees. Additionally, he serves as a director of the Hartford Land Company and the Rutland Economic Development Corporation.

Energy Conservation and Load Management The primary purpose of Conservation and Load Management programs is to offset the 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 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. The PSB is revising the structure and scope of the EEU to facilitate the EEU participation in the FCM, lengthen its planning horizon and expand its scope to include non-electric efficiency.

We have retained the obligation to provide certain demand side management programs, including demand response programs primarily delivered through rate design and those targeted at deferral of our transmission and distribution projects, as identified in DUP. DUP is designed to ensure that safe, reliable delivery services are provided at least cost. 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 in 2007. Several areas of the state, including two areas within our service territory, are the subject of the geo-targeting program to test the ability to defer wire upgrades with intense energy efficiency programs. The PSB approved a similar process for the bulk transmission lines owned and operated by Transco. In 2006, 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.

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 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

Risks Relating to Our Business 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 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 8, Note 9 - Retail Rates and Regulatory Accounting, for additional information.

We are subject to the effects of changes in Vermont state government resulting from elections of public officials, including the governor and appointees to 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. 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 recovered storm response-related costs from the 2008 major storm under our alternative regulation plan and $3.4 million of 2010 major storm costs qualify as an exogenous factor; however, we 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. Also, see Part II, Item 7, Retail Rates and Regulatory Accounting.

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 and upgrading of facilities, 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. We believe that we are materially in compliance with all applicable environmental and safety laws and regulations; however, there can be no assurance that we will not incur significant costs or liabilities in the future.

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 at the federal and state government levels, which could potentially lead to additional rules and regulations that may 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.

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 continues to slowly 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 and investments in Transco.

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 securities in our nuclear decommissioning trust and in our Rabbi 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-Québec and VYNPC. The power supply contracts with Vermont Yankee and Hydro-Québec comprise the majority of our total annual energy purchases. Combined, these contracts account for the majority 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-NE 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. We cannot predict the outcome of this matter or how it might affect us.

Deliveries under the current contract with Hydro-Québec end in 2016, but the level of deliveries will begin to decrease after 2012. 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. In August 2010, we signed a new contract for ongoing Hydro-Québec supplies. The agreement is subject to certain government approvals.

For additional information on our material power supply contracts, see Part II, Item 8, Note 19 – Commitments and Contingencies – Long-term Power Purchases.

An economic downturn and customers' conservation efforts could reduce energy consumption and adversely affect our results of operations, cash flows or financial position. 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, prolonged recoveries 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. Anticipated consumer demand is reflected in base rates set annually under the plan; if demand was more or less during the year than the level reflected in rates, the difference would not be adjusted within the mechanism of our alternative regulation plan. The effect of unanticipated increases or decreases in consumer demand on our revenue will be offset in part by the power cost and earnings sharing adjustment mechanism in the alternative regulation plan. Also see Part II, Item 8, Note 9 - Retail Rates and Regulatory Accounting, for additional information.

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-NE 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, 2010, assuming no stranded cost recovery would be allowed through a rate mechanism. We would also be required to record pension and postretirement costs of $27.5 million on a pre-tax basis to Accumulated Other Comprehensive Loss and $0.5 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). They require advance notice of stockholder proposals and stockholder nominations to the board of directors and 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 in 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-NE 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.

In 2010, we sold an aggregate of 1,498,745 shares in open market trading and direct placements under an "at-the-market" program for aggregate net proceeds of approximately $30 million. The proceeds were used for general corporate purposes. We also issued $30 million of first mortgage bonds, Series VV, due December 15, 2020 as security for $30 million VEDA tax-exempt Recovery Zone Facility Bonds, Central Vermont Public Service Corporation Issue, Series 2010 bonds. The proceeds will be used to fund certain capital improvements to our production, transmission, distribution and general facilities.

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. 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 it and VELCO paid in the past.

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 2010, Moody's Investors Service affirmed our issuer rating of Baa3, which is investment grade. Maintaining 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-Québec and Vermont Yankee begin to expire one year from now, these ratings become even more important due to the role they play in pricing and collateral requirements.

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, if costs exceeded amounts allowed to be recovered in our rates. 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 ™ project 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 to our business.

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 PSNH. 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, 2010, our electric transmission and distribution systems consisted of approximately 616 miles of overhead transmission lines, 8,486 miles of overhead distribution lines and 478 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 722 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, New York and Bennington, Vermont, and with the submarine cable of New York Power Authority near Plattsburgh, New York; 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-Québec near Derby, Vermont and through the Highgate converter station and tie line that we jointly own with several other Vermont utilities.

VELCO's wholly owned subsidiary, VETCO, has approximately 54 miles of high-voltage DC transmission lines connecting with the transmission line of Hydro-Québec at the Quebec-Vermont border in the Town of Norton, Vermont and connecting with the transmission line of New England Electric Transmission Corporation, a subsidiary of National Grid USA, at the Vermont-New Hampshire border near New England Power Company's Moore hydroelectric generating station.

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

Item 4. 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 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	
2010	High	Low
First Quarter	**$21.48**	**$18.72**
Second Quarter	**$22.83**	**$19.00**
Third Quarter	**$22.14**	**$19.09**
Fourth Quarter	**$22.70**	**$19.75**
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

(b) As of December 31, 2010, there were 5,646 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 2010 and 2009.

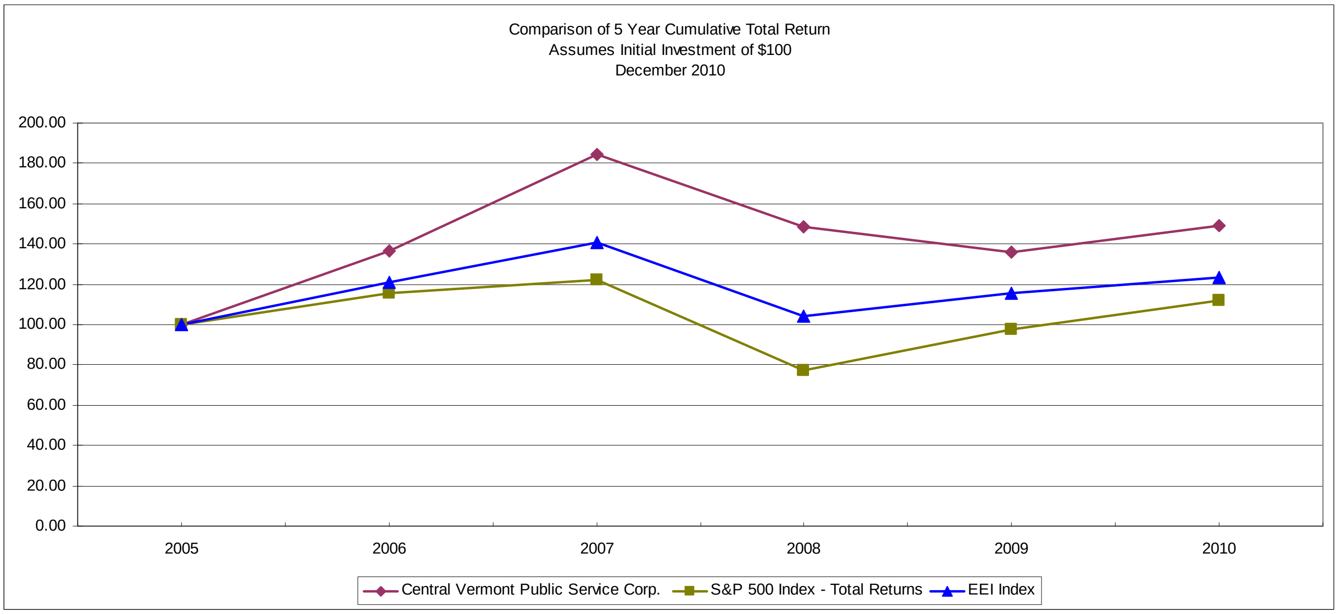
So long as any Senior Preferred Stock is outstanding, except as otherwise authorized by vote of two-thirds of such class, if the Common Stock Equity (as defined) is, or by the declaration of any dividend will be, less than 20 percent of Total Capitalization (as defined), dividends on Common Stock (including 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, 2010, the Common Stock Equity of our unconsolidated company was 54.4 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, 2010, $85.8 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 follows:

The SEC requires that we include in its Annual Report on Form 10-K a line-graph presentation comparing cumulative, five-year stockholder returns on an indexed basis with the S&P 500 Stock Index and either a published industry or line-of-business index or an index of peer companies selected by us. The company has selected for its peer group index a stock index compiled by EEI, because it is the most comprehensive and representative index because as it includes stock performance data for investor-owned electric utility companies. During the five year period shown (2005-2010), we outperformed both the EEI Index and the S&P 500 Stock Index.



	2005	2006	2007	2008	2009	2010
CVPS	100.00	136.64	184.42	148.43	135.81	149.17
S&P 500	100.00	115.79	122.16	76.97	97.33	112.00
EEI Index	100.00	120.76	140.76	104.30	115.47	123.60

Item 6. Selected Financial Data

The following table summarizes five years of selected consolidated financial data.

(in thousands, except per share amounts)

	2010	2009	2008	2007	2006
Income Statement					
Operating revenues	**$341,925**	$342,098	$342,162	$329,107	$325,738
Income from continuing operations	**$20,954**	$20,749	$16,385	$15,804	$18,101
Income from discontinued operations (a)	**0**	0	0	0	251
Net income	**$20,954**	$20,749	$16,385	$15,804	$18,352
Per Common Share Data					
Basic earnings from continuing operations	**$1.66**	$1.75	$1.53	$1.52	$1.65
Basic earnings from discontinued operations	**0.00**	0.00	0.00	0.00	0.02
Basic earnings per share	**$1.66**	$1.75	$1.53	$1.52	$1.67
Diluted earnings from continuing operations	**$1.66**	$1.74	$1.52	$1.49	$1.64
Diluted earnings from discontinued operations	**0.00**	0.00	0.00	0.00	0.02
Diluted earnings per share	**$1.66**	$1.74	$1.52	$1.49	$1.66
Cash dividends declared per share of common stock	**$0.92**	$0.92	$0.92	$0.92	$0.69
Balance Sheet					
Long-term debt (b)	**$188,300**	$201,611	$167,500	$112,950	$115,950
Capital lease obligations (b)	**$3,471**	$4,313	$5,173	$5,889	$6,612
Redeemable preferred stock (b)	**$0**	$0	$1,000	$2,000	$3,000
Total capitalization (b)	**$472,553**	$445,401	$401,206	$317,700	$312,968
Total assets (c)	**$710,746**	$632,152	$626,126	$540,314	$500,938

(a) For 2006, includes Catamount, which was sold in the fourth quarter of 2005.

(b) Amounts exclude current portions.

(c) We invested $34.9 million in Transco in 2010, $20.8 million in 2009, $3.1 million in 2008, $53 million in 2007 and $23.3 million in 2006.

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 are based on, and should be read in conjunction with, the accompanying Consolidated Financial Statements. The discussion below also includes non-U.S. 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-U.S. GAAP measure should not be considered as an alternative to our consolidated fully diluted earnings per share determined in accordance with U.S. 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 PSB, 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. 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. By order dated March 3, 2011, the PSB approved further amendments to the alternative regulation plan that: 1) extend its duration until December 31, 2013; 2) alter the methodology for implementing the non-power-cost cap contained in the plan; 3) reset our allowed ROE; and 4) remove provisions no longer applicable to the provision of our services. These amendments are consistent with the terms of an ARP MOU that was filed with the PSB on December 21, 2010, except that the PSB approved an ROE for us for 2011 of 9.45 percent, rather than the 9.59 percent contained in the ARP MOU.

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 the size of 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 remained essentially flat with 2010 sales being higher than 2000 sales by 1.6 million kWh, or less than one percent. Annual charges between 2000 and 2010 ranged from a decrease of over 3 percent in 2009 to increases of over 2 percent in 2004 and 2005, mainly resulting from economic conditions. We currently have sufficient power resources to meet or exceed our forecasted load requirements through March 2012.

Our non-regulated wholly owned subsidiary CRC owns SmartEnergy Water Heating Services, Inc., which operates a rental water heater business. This is not a significant business activity for us.

EXECUTIVE SUMMARY

Our consolidated 2010 earnings were $21 million, or $1.66 per diluted share of common stock. This compares to consolidated 2009 earnings of $20.7 million, or $1.74 per diluted share of common stock and consolidated 2008 earnings of $16.4 million, or $1.52 per diluted share of common stock. The primary drivers of earnings variances for the three years are described in Results of Operations below.

Major Storm: A major winter storm knocked out power to more than 91,000 of our retail customers throughout our service territory in February 2010. The cost of this storm was $3.1 million, making it one of the five most-expensive storms in our history. In May 2010 and December 2010, additional major storms resulted in service restoration costs of $1.1 million and $1.4 million, respectively. Our rates include a five-year average of storm restoration costs, but given the magnitude of these major storms, that average will not fully recover our current costs. Any incremental service restoration costs for major storms above the level currently reflected in our retail rates may be deferred throughout the year for recovery through the ESAM and exogenous effects provisions of our alternative regulation plan.

Health Care Legislation: In March 2010, the federal Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act of 2010 were passed into law. Together, the legislation required us to record $0.8 million of additional income tax expense related to postretirement medical costs. Also, see Exogenous Effects and Income Tax Matters below for additional information.

Exogenous Effects: As a result of the major storms and health care legislation items described above, we deferred $4.2 million of costs in 2010 for future recovery. See Retail Rates and Alternative Regulation below for additional information.

New Hydro-Québec Agreement: On August 12, 2010 we, along with GMP, VPPSA, Vermont Electric Cooperative, Inc., Vermont Marble, Town of Stowe Electric Department, City of Burlington, Vermont Electric Department, Washington Electric Cooperative, Inc. and the 13 municipal members of VPPSA (collectively, the "Buyers") entered into an agreement for the purchase of shares of 218 MW to 225 MW of energy and environmental attributes from HQUS commencing on November 1, 2012 and continuing through 2038. For more information on this agreement, see Power Supply Matters below.

Financial Initiatives: Our financial initiatives include maintaining sufficient liquidity to support ongoing operations, the dividend on our common stock and investments 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 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.

Alternative Regulation Plan I: On September 30, 2008, the PSB issued an order approving our alternative regulation plan. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have petitioned for an extension through December, 2013. The plan allows for quarterly PCAM adjustment to reflect changes in power supply and transmission-by-others costs); annual base rate adjustments to reflect changing costs; and an annual ESAM adjustment to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity is 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 ESAM 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 customers in a future period. If the actual return on equity of our regulated business falls between 75 and 125 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and customers. Any earnings shortfall in excess of 125 basis points below the allowed return on equity is fully recovered from customers. As such, the minimum return for our regulated business is 100 basis points below the allowed return. These adjustments are made at the end of each fiscal year.

The ESAM also provides for an exogenous effects provision. Under this provision, we are allowed to defer the unexpected impacts, to the extent these costs exceed $0.6 million, of changes in GAAP, tax laws, FERC or ISO-NE rules and major unplanned operation, maintenance costs, such as those due to major storms and other factors including loss of load not due to variations in heating and cooling temperatures.

On December 31, 2009, the PSB issued its order approving our 2010 base rate filing, which increased rates 5.58 percent, effective for bills rendered beginning January 1, 2010. The allowed rate of return for 2010, calculated in accordance with the plan, was 9.59 percent.

On February 2, 2010, the PSB held a prehearing conference, followed by a workshop, to consider the proposal to amend the non-power cost cap formula of our alternative regulation plan to allow for full cost recovery for new initiatives arising after the effective date of the plan. The DPS supported the proposal, and the 2010 base rate filing increase approved by the PSB included recovery of costs for two new initiatives. On September 3, 2010, the PSB approved the implementation of a new initiatives adder under our alternative regulation plan. In order to qualify for treatment as a new initiative the following criteria must be met: 1) the risk associated with implementing the new initiative is of a nature that is distinct from the ordinary business risk that we assume in discharging our public service obligation, and 2) the costs associated with implementing the new initiative are material. In our 2010 base rate filing we were allowed recovery of $0.2 million for a new initiative that does not meet the PSB criteria. This amount will be returned to customers in 2011.

Using the methodology specified in our alternative regulation plan, we estimated the 2010 return on equity from the regulated portion of our business to be approximately 9 percent. We are required to file this calculation with the PSB by May 1, 2011. No ESAM adjustment was required since this return was within 75 basis points of our 2010 allowed return on equity of 9.59 percent.

In 2010, under the exogenous effects provision of the ESAM, we deferred $4.2 million of costs related to three major storms and tax law changes. On January 31, 2011 we filed with the PSB for recovery of these costs through the ESAM over a 12-month period commencing on July 1, 2011. The PSB has not yet acted on this filing.

The PCAM adjustments for 2010 were calculated to be an over-collection of $0.5 million in the first quarter, an under-collection of $1 million in the second quarter and an over-collection of less than $0.1 million in the third quarter. The over-collection in the first quarter was recorded as current liability and returned to customers over the three months ended September 30, 2010. The under-collection in the second quarter was recorded as a current asset and recovered from customers over the three months ended December 31, 2010. The over-collection in the third quarter was recorded as current liability and will be returned to customers over the three months ended March 31, 2011. We filed PCAM reports, including supporting documentation, each quarter with the PSB identifying the over- and under-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 PCAM adjustment for the fourth quarter of 2010 was an over-collection of $5.2 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending June 30, 2011. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

On February 24, 2011, we filed a request with the PSB to offset the $4.2 million 2010 ESAM deferral against the $5.2 million fourth quarter 2010 PCAM over-collection and return the net refund of $1 million to customers over the three months ending June 30, 2011. The DPS supports our request. The PSB has not yet acted on the request.

On May 1, 2010, we filed our 2009 ESAM calculation using the methodology specified in our alternative regulation plan. The 2009 return on equity from the regulated portion of our business was 9.87 percent. No ESAM adjustment was required in 2009 since this return was within 75 basis points of our 2009 allowed return on equity of 9.77 percent.

The PCAM adjustments for 2009 were calculated to be over-collections of $0.6 million in the first quarter, $0.5 million in the second quarter, $0.6 million in the third quarter and $1 million in the fourth quarter. These over-collections were recorded as current liabilities. We filed PCAM reports, including supporting documentation, each quarter 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 2009 over-collections were returned to customers over the three months ended September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010, respectively.

On November 1, 2010, we submitted two versions of a base rate filing for the rate year beginning January 1, 2011. The first version was for a $21.8 million or 7.46 percent increase in retail rates pursuant to our existing alternative regulation plan, reflecting an allowed ROE of 9.18 percent as a result of the existing ROE adjustment formula.

The second version was for a $24.4 million or an 8.34 percent increase in retail rates, reflecting an allowed ROE of 10.22 percent. This increase was premised upon the PSB approving certain modifications to our existing alternative regulation plan as discussed below in the section titled Alternative Regulation Plan II.

Under our existing 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, less a 1 percent productivity adjustment. The non-power costs associated with the implementation of our Asset Management Plan and our CVPS SmartPower™ project are excluded from the non-power cost cap. Our 2011 non-power costs did not exceed the non-power cost cap.

On December 3, 2010, the DPS recommended that the PSB approve our requested 7.46 percent base rate adjustment under the existing alternative regulation plan with certain conditions.

On December 21, 2010, we filed the ARP MOU between us and the DPS with the PSB regarding certain amendments to the alternative regulation plan including the ROE provisions. As part of the settlement, an agreement was also reached with respect to our 2011 base rate filing. Under the ARP MOU we would be permitted to set our ROE for 2011 at 9.59 percent and implement a 7.67 percent retail rate increase effective with bills rendered January 1, 2011.

On December 29, 2010, the PSB issued an order allowing us to implement a 7.46 percent increase in retail rates, reflecting an allowed ROE of 9.18 percent, effective with bills rendered January 1, 2011. The PSB concluded that there was not sufficient time to conduct a meaningful assessment of the issues raised by the ARP MOU, particularly given the absence of pre-filed supporting testimony. The PSB has opened an investigation into our existing rates in order to assess whether further adjustment is necessary pending its review of the ARP MOU. As discussed below in Alternative Regulation II, the PSB has issued an order concerning our request to modify and extend our existing alternative regulation plan. This order will require consideration in the PSB's investigation into our current rates. At this time we do not expect that this will result in any change to the 7.46 percent rate increase implemented on January 1, 2011.

Alternative Regulation Plan II: On June 30, 2010, we filed a required Alternative Regulation Plan Analysis of Plan Performance with the PSB. This analysis evaluated the effectiveness of the Plan's performance in achieving the goals of Vermont alternative regulation. As described in the evaluation, the implementation of the current plan has helped to advance these goals; however, we also identified concerns and impediments that limit its overall effectiveness in satisfying all of the objectives of Vermont alternative regulation.

To address these concerns, on July 6, 2010 we petitioned the PSB to approve changes to the current plan to: a) extend its duration; b) alter the methodology for implementing the non-power cost cap; and c) reset the allowed ROE as noted above to 10.22 percent. If these changes are approved as initially proposed, the revised plan will expire on December 31, 2013 and the allowed ROE will be reset as of January 1, 2011. Thereafter, the existing annual ROE adjustment methodology would apply for the duration of the plan.

The ARP MOU filed on December 21, 2010 would provide final resolution to all issues regarding our petition to modify and extend our existing alternative regulation plan. Under the ARP MOU, the term of the alternative regulation plan would be extended through 2013 and the allowed ROE would be set at 9.59 percent for 2011. In addition, the ARP MOU provides for a modification to the alternative regulation plan to include a benchmarking mechanism that affects the non-power cost cap for rate years 2012 and 2013. There is also a provision to adjust the non-power cost cap for any cost of service change resulting from an ROE change.

As discussed above, the PSB felt a meaningful assessment of the ARP MOU could not occur before January 1, 2011 and opened an investigation. Technical hearings on the ARP MOU were held on January 5 and 6, 2011. We expect to receive a PSB order in the first quarter of 2011. The PSB may approve, reject or modify the ARP MOU. Based on its ruling on the ARP MOU, the retail rate increase ultimately approved for 2011 may be modified in the investigation. By order dated March 3, 2011, the PSB approved further amendments to the alternative regulation plan that: 1) extend its duration until December 31, 2013; 2) alter the methodology for implementing the non-power-cost cap contained in the plan; 3) reset our allowed ROE; and 4) remove provisions no longer applicable to the provision of our services. These amendments are consistent with the terms of an ARP MOU that was filed with the PSB on December 21, 2010, except that the PSB approved an ROE for us for 2011 of 9.45 percent, rather than the 9.59 percent contained in the ARP MOU. At this time we do not expect there will be any change to the 7.46 percent rate increase implemented on January 1, 2011.

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 November 30, 2009, we filed the 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 reductions contemplated by the implementation of CVPS SmartPower^{TM}. 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. By December 31, 2010 we had reduced staffing levels to 517 employees. 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.

On March 31, 2010, the PSB approved the Staffing MOU. The Staffing MOU allows CVPS to recover all reasonable costs associated with the staff reductions in accordance with our new initiatives amendment to the non-power cost cap formula of our alternative regulation plan. As discussed above, for these costs to qualify as a new initiative under the plan they would need to meet the criteria established by the PSB.

CVPS SmartPower™ 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 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.

On April 15, 2010, we signed an agreement with the DOE for our portion of the Smart Grid stimulus grant and project and the agreement became effective April 19, 2010. The agreement includes provisions for funding and other requirements. We are eligible to receive reimbursement of 50 percent of our total project costs incurred since August 6, 2009, up to $31 million. Through December 31, 2010, we incurred $4.7 million of costs, of which $2.4 million were operating expenses and $2.3 million were capital expenditures. We have submitted requests for reimbursement of $2.3 million and have received $1.7 million to date.

On April 7, 2010, we filed the CVPS SmartPower™ MOU with the PSB that included, among other things, the agreement we reached with the DPS on the recovery of costs we will incur due to CVPS SmartPower™ implementation. We received the PSB's order approving the cost recovery principles contained in the CVPS SmartPower™ MOU on August 6, 2010. On September 3, 2010, the PSB recognized the CVPS SmartPower™ plan as an authorized initiative under the new initiative adder discussed above.

The CVPS SmartPower™ MOU allows us to defer the difference between the actual costs included in the approved CVPS SmartPower™ plan and amounts collected through rates. Actual 2010 costs exceeded the amounts collected through rates by less than $0.1 million and were recorded as a regulatory asset.

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the DOE under the ARRA; however, the grant reimbursement was not reflected in our 2010 rates. Grant reimbursements of $1.2 million for 2010 operating costs were recorded as a regulatory liability. Expected grant reimbursements are reflected in 2011 rates.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Cash Flows At December 31, 2010, we had cash and cash equivalents of $2.7 million and at December 31, 2009, we had cash and cash equivalents of $2.1 million.

Our primary sources of cash in 2010 were from our electric utility operations, distributions received from affiliates, income tax refunds, reduced cash collateral deposits, reimbursements from restricted cash of debt-financed project costs, borrowings under our revolving credit facility, net proceeds from our at-the-market common stock issuance program and a long-term debt financing. In 2010, we received $1.7 million of federal stimulus fund reimbursements for operating and capital costs from the DOE. Our primary uses of cash in 2010 included capital expenditures, investments in affiliates, a restricted cash fund comprised of unreimbursed VEDA bond financing proceeds, common and preferred dividend payments, repayments of borrowings under our revolving credit facility, contributions to the pension and postretirement medical plans and working capital needs.

Operating Activities: Operating activities provided $53.5 million in 2010, compared to $42.1 million in 2009. The increase of $11.4 million was primarily due to: $13.2 million from our 5.58 percent rate increase effective January 1, 2010; lower transmission expenses of $8.9 million due to a higher level of NOATT reimbursements; $7.1 million from replacing power contract-related cash collateral with a letter of credit; $3.5 million in earnings from affiliates resulting from our 2009 investment in Transco; $0.6 million less in employee benefit plan funding due to lower benefit costs in 2010; $0.9 million of federal stimulus funds received in 2010. These items were partially offset by $11.3 million less from resale sales as a result of reduced contract rates for resale power sales; $5.2 million increase in operations and maintenance expense from increased storm costs; and a $2.8 million increase in purchased power expense due to the planned outages at the Vermont Yankee and Millstone Unit #3 nuclear plants in 2010. We received lower net income tax refunds of $5.7 million in 2010 compared to $6.5 million in 2009. Tax refunds in both years primarily related to our elections for federal bonus depreciation on our assets. The 2009 tax refunds also included bonus depreciation on our share of Transco assets placed in service during 2008.

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.

At December 31, 2010, our retail customers' accounts receivable over 60 days totaled $2.6 million compared to $2.5 million at December 31, 2009, which was an increase of 3.6 percent. At December 31, 2009, our retail customers' accounts receivable over 60 days totaled $2.5 million compared to $2.7 million at December 31, 2008, which was a decrease of 5.4 percent.

Investing Activities: Investing activities used $91.4 million in 2010, compared to $52.9 million in 2009. The increase of $38.5 million was primarily due to $29.8 million of investments in restricted cash and $14.1 million of increased equity investments in Transco in December 2010. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements. In 2010, we also received $6.3 million of restricted cash reimbursements, and $0.8 million of federal stimulus funds, related to capital expenditures.

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.

Financing Activities: Financing activities provided $38.5 million in 2010, compared to $6.2 million in 2009. The increase of $32.3 million was primarily from our at-the-market common stock issuance program and long-term debt financing. In 2010, we used $9.6 million of net proceeds to repay our revolving credit facility.

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. Also, see Financing below.

Transco In December 2010, we invested an additional $34.9 million in Transco and our direct ownership interest increased from 33.35 percent to 36.68 percent as a result of additional member contributions from Vermont utilities. Our total direct and indirect interest in Transco increased from 38.68 percent to 41.02 percent.

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.

Based on current projections, Transco expects to need additional equity capital from 2011 through 2015, 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. We are currently considering additional investments of approximately $11.6 million in 2011, $46.6 million in 2012, $60.6 million in 2013 and $0 in both 2014 and 2015, but the timing and amounts 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 our core business provide value to customers and shareholders alike. They provide shareholders with a return on investment while helping to maintain and improve reliability for our customers.

Pending Acquisitions *Vermont Marble Power Division:* On April 30, 2010, we signed a purchase and sale agreement with Omya, Inc. to purchase certain generating, transmission and distribution assets of Vermont Marble located in the State of Vermont. Under this agreement, we will pay $33.2 million for the transmission and distribution assets and generating assets comprised of four hydroelectric generating stations. The agreement contains usual and customary purchase and sale terms and conditions and is contingent upon federal and state regulatory approvals.

With Omya, Inc., we filed a joint petition with the PSB on August 2, 2010, requesting that they consent to the proposed sale by Omya and purchase by us of assets used in the public service business of Vermont Marble and approve certain related matters. As part of the proposed purchase and sale, we will acquire from Vermont Marble, among other things, four hydroelectric facilities on Otter Creek and Vermont Marble's transmission and distribution facilities, which include approximately 56 miles of 46 kV transmission lines, 11 miles of 2.4/4.16 kV distribution lines, one distribution substation in the Village of Proctor, and two transmission substations. On September 14, 2010, the PSB held a prehearing conference and subsequently established a schedule for resolution of the docket including technical hearings and the filing of final legal briefs.

On October 28, 2010, we received approval from FERC, subject to certain conditions, for the proposed transaction.

On February 25, 2011, we filed an MOU between us, the DPS, the Town of Proctor and Omya, with the PSB that resolves all the outstanding issues between the parties concerning our acquisition of Vermont Marble. As part of the settlement, we will pay $28.3 million for the generating assets and approximately $1 million for the transmission and distribution assets. We will be allowed recovery from customers of $27 million for the generating assets and the $1 million for the transmission and distribution assets.

The agreement includes a five-year, six-step phase-in of residential rate changes for existing Vermont Marble customers, which will be funded by Omya up to an amount estimated to be approximately $1.1 million. The agreement also requires creation of a value sharing pool that provides for certain excess value received by us to be split between our customers, Omya and our shareholders if energy market prices and hydro improvements create more value than anticipated.

On March 4, 2011 we signed an amended and restated purchase and sale agreement with Omya, Inc. to incorporate the terms of the MOU filed on February 25, 2011.

Readsboro Electric Department: On October 27, 2010, we signed a purchase and sale agreement with Readsboro. The $0.4 million purchase price includes all of the assets of Readsboro including about 14 miles of distribution line and associated equipment, and the exclusive franchise Readsboro holds to serve its 319 customers. The sale is contingent upon approval by the PSB. On February 24, 2011 we, along with the DPS and Readsboro, filed a petition with the PSB that resolves the issues outstanding in our acquisition of Readsboro. The PSB is expected to rule on the petition for approval of the transaction in the first half of 2011.

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 or improve our current dividend level.

Dividend Reinvestment Plan Our Dividend Reinvestment Plan used Treasury shares as the source of common shares to meet reinvestment obligations since July 2007, resulting 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 large customer filed for bankruptcy protection. In December 2010, the PSB approved the final bankruptcy plan and in January 2011 the court approved the plan and final settlement. As of December 31, 2010, we reversed the reserve of $1.1 million that was previously recorded in 2009 and received payment in January 2011.

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 to fund our business over the next few years. Prolonged upheaval in the global 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-NE or third parties. An extended unplanned Vermont Yankee plant outage could involve cost recovery 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 relative to our allowed ROE. See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks.

Global Economic Conditions 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 *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 that expires on November 2, 2011. The Credit Agreement 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. At December 31, 2010, $13.7 million in loans and $5.5 million in letters of credit were outstanding under this credit facility. We had periodic borrowings under this facility during 2010. In 2011 we intend to renew or replace this facility.

We also have a three-year, $15 million unsecured revolving credit facility with a different lending institution pursuant to a Credit Agreement dated December 22, 2010 that expires in December 2013. This facility replaced a 364-day, $15 million unsecured revolving credit facility that matured on December 29, 2010. The purpose and obligation under this credit agreement are the same as described above. At December 31, 2010, there were no borrowings or letters of credit outstanding under the credit facility and through December 31, 2010, and we have not used this facility for borrowings or letters of credit.

Common Equity Issue: On November 6, 2009, we filed a Registration Statement with the SEC on Form S-3, 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 that allowed us to issue up to $45 million of shares under an “at-the-market” program.

On December 3, 2010 we completed the sale of shares offered under the program. During 2010, we issued 1,498,745 shares for net proceeds of $30 million at an average price of $20.40 per share.

Long-term Debt Issues: On July 15, 2010, we entered into a commitment to issue $40 million of first mortgage bonds at 5.89 percent on June 15, 2011 in a private placement transaction, pending regulatory approvals. The proceeds will be used to help finance our capital expenditures, debt retirements, investments in Transco and other corporate purposes. These bonds will be issued to one purchaser under a shelf facility that was put in place on February 4, 2011 after receiving regulatory approval on November 30, 2010. The shelf facility allows us to issue up to an additional $60 million of first mortgage bonds directly to the purchaser through December 31, 2012. Neither party has any obligation to issue or purchase the additional $60 million first mortgage bonds available under the shelf facility.

On December 2, 2010, the VEDA issued $30 million of tax-exempt Recovery Zone Facility Bonds, Central Vermont Public Service Corporation Issue, Series 2010 bonds and loaned the proceeds to us under a Loan and Trust Agreement dated December 1, 2010. The bonds carry a fixed interest rate of 5 percent and will mature on December 15, 2020. The proceeds will be used to fund certain capital improvements to our production, transmission, distribution and general facilities. The VEDA bonds are secured by a $30 million issue of first mortgage bonds, Series VV, issued under our Indenture of Mortgage dated as of October 1, 1929, as amended and supplemented. As security, the terms of the Series VV first mortgage bonds mirror those of the VEDA bonds. VEDA has no obligation to pay interest and principal on the VEDA bonds except from proceeds provided by us. There are no interim sinking fund payments due prior to the maturity of the VEDA bonds, and they are not callable prior to maturity at our option. The bond proceeds are held in trust and we access these bond proceeds as reimbursement for capital expenditures made under certain production, transmission, distribution and general facility projects. The trust funds holding the bond proceeds are recorded as restricted cash on our balance sheet.

Our first mortgage bond and industrial/economic development bond 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 and C.V. Realty, Inc. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions, a breach of warranty or performance of an obligation, or the levy of significant judgments, attachments against our property or insolvency. 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 $20 million in 2011, $0 in 2012, $5.8 million in 2013, $0 in 2014 and $5 million in 2015.

Industrial/economic development bonds: The CDA and VIDA bonds are tax-exempt, floating rate, monthly demand revenue 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. These two series of bonds are supported by letters of credit, discussed below.

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 the two revenue bond issues totaling $10.8 million, discussed above. 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, 2010, there were no amounts drawn under these letters of credit.

Covenants: At December 31, 2010, 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 financial covenants include maximum debt to total capitalization of 65 percent, and minimum interest coverage of two times interest on first mortgage bonds. At December 31, 2010, our earnings covered our first mortgage bond interest 4.3 times. At December 31, 2010, we had the ability to declare $85.8 million additional dividends or other restricted payments. Also, at December 31, 2010, we were permitted to incur $32.4 million of additional mortgage bond debt and $86.4 million of unsecured debt, of which $86.4 million could be short-term.

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system. In 2010, capital expenditures were $33 million.

Capital expenditures for the years 2011 to 2015 are expected to range from $36 million to $60 million annually, including an estimated total of more than $60 million for CVPS SmartPower™ over the five-year period. A portion of this CVPS SmartPower™ project total will be funded by the Smart Grid Stimulus Grant and this grant has reduced the 2011 to 2015 estimated spending range above. Further discussion of the Smart Grid Stimulus Grant can be found above in Retail Rates and Alternative Regulation - CVPS SmartPower™.

Future Liquidity Needs In order to meet our expected levels of capital expenditures and investments in affiliates, we expect to issue additional debt in 2011-2013, and additional equity in 2012 and 2013.

Performance Assurance We are subject to performance assurance requirements through ISO-NE under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $3.2 million with ISO-NE. 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, 2010, we had posted $6.6 million of collateral under performance assurance requirements for certain of our power contracts, $5.5 million of which was represented by a letter of credit and $1.1 million of which was represented by cash and cash equivalents. 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 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.

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 also have outstanding a $30 million issue of first mortgage bonds, Series VV as security for the $30 million VEDA bonds described in Financing, above. Until the third quarter of 2010, we leased most vehicles and related equipment under operating lease agreements. These operating lease agreements are described in Part II, Item 8, Note 19 - Commitments and Contingencies.

Commitments and Contingencies We have material power supply commitments for the purchase of power from VYNPC and Hydro-Québec. 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 VY PPA between VYNPC and Entergy-Vermont Yankee. 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 4 - Investments in Affiliates.

We are subject to extensive federal, state and local environmental regulations that monitor, among other things, emission allowances, pollution controls, maintenance and upgrading of facilities, site remediation, equipment upgrades and management of hazardous waste. We believe that we are materially in compliance with all applicable environmental and safety laws and regulations; however, there can be no assurance that we will not incur significant costs and liabilities in the future. See Part I, Item 1A. Risk Factors and Part II, Item 8, Note 19 – Commitments and Contingencies.

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. Under the terms of the agreements with Catamount and Diamond Castle Holdings, we agreed to indemnify them, and certain of their respective affiliates as described in Part II, Item 8, Note 19 - Commitments and Contingencies.

Contractual Obligations Significant contractual obligations as of December 31, 2010 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)	$208.3	$20.0	$5.8	$5.0	$177.5
Interest on long-term debt (b)	157.7	12.1	23.0	22.6	100.0
Notes Payable (c)	13.7	13.7	0.0	0.0	0.0
Interest on notes payable (b)	0.2	0.2	0.0	0.0	0.0
Capital lease (c)	5.3	1.3	2.3	1.7	0.0
Operating leases - vehicle and other (d)	5.4	1.8	2.5	1.0	0.1
Purchased power contracts (e)	1,861.2	148.5	209.0	183.2	1,320.5
Nuclear decommissioning and other closure costs (f)	6.7	1.4	3.0	2.3	0.0
Other purchase obligations (g)	1.5	1.5	0.0	0.0	0.0
Total Contractual Obligations	$2,260.0	$200.5	$245.6	$215.8	$1,598.1

(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 15 - Long-Term Debt and Notes Payable.
(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, 2010.
(e) Forecasted power purchases under long-term contracts with Hydro-Québec, 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 2011, we expect to contribute a total of $5.7 million to our pension and postretirement medical trust funds. Future payments will vary based on changes in the fair value of plan assets, the benefit obligations and actuarial assumptions. Traditionally, we have recovered these costs through rates. Additional obligations related to our nonqualified pension plans are approximately $0.1 million per year.

Income Taxes: At December 31, 2010, 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	
	2010	2009	**2010**	2009
Common stock equity	$272,728	$231,423	57%	52%
Preferred stock	8,054	8,054	2%	2%
Long-term debt	188,300	201,611	40%	45%
Capital lease obligations	3,471	4,313	1%	1%
	$472,553	$445,401	100%	100%

Credit Ratings On December 6, 2010, Moody's affirmed our Baa3 corporate issuer rating (an investment-grade rating), our Baa1 senior secured bond rating and our Ba2 preferred stock rating. At the same time, Moody's affirmed our stable rating outlook. Prior to December 4, 2009, we were rated by S&P. On December 10, 2009, S&P withdrew its ratings of us 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 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-NE. While our current 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 issuer 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.

OTHER BUSINESS RISKS

Our 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, below

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-Québec contract deliveries through our current contract end in 2016, but the average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015. In August 2010, we signed a new contract for ongoing Hydro-Québec supplies. The agreement is subject to certain government approvals. We continue to seek out other power sources but there is a risk that future sources available may not be as reliable and the price of such replacement power could be significantly higher than what we have in place today. However, we have 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. See Power Supply Matters, below.

Wholesale Power Market Price Risk: Our material power supply contracts are with Hydro-Québec and VYNPC. These contracts comprise the majority of our total annual 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. We do not plan to renew the outage insurance. The PCAM 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 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 including, 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 be, among other things, a charge to operations of $11.8 million pre-tax at December 31, 2010. 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 an asset is considered impaired when the anticipated undiscounted cash flow from the asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized in 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 2010, 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 5.4 percent. A one percent change in line losses would result in a $2.9 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 $21 million at December 31, 2010 and $20.8 million at December 31, 2009. We believe that these assumptions have resulted in a reasonable approximation of our unbilled revenues and are reasonably likely to continue.

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.

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, based on future projections, expressed in today's dollars. The selection methodology used in determining the discount rate includes portfolios of "Aa"-rated 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, 2010, the pension discount rate changed from 6 percent to 5.75 percent and the postretirement medical discount rate changed from 5.5 percent to 5.25 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: 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 long-term ROA assumption was 7.85 percent as of December 31, 2010 and 2009. This rate was also used to determine the annual expense for 2010 and will be used to determine the 2011 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 both 2010 and 2009.

Post-retirement 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 at the national level. For measuring annual cost, we assumed an 8.5 percent annual rate of increase in the per capita cost of covered health care benefits for fiscal 2010, for pre-age 65 and post-age 65 participant claims costs. After three years, the rate is assumed to decrease by 0.5 percent each year, when an estimated ultimate rate of 5 percent is reached in 2019.

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 17 - 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, 2010	($2,119)	$2,159	$0	$0
Effect on 2010 net period benefit cost	($5)	($1)	($263)	$263
Other Postretirement Medical Benefit Plans				
Effect on accumulated postretirement benefit obligation as of December 31, 2010	($583)	$596	$0	$0
Effect on 2010 net periodic benefit cost	($71)	$72	($38)	$38

Fair Value Measurements We follow FASB's fair value guidance that establishes criteria to be considered when measuring the fair value of assets and liabilities and requires disclosures about fair value measurements.

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 and other short-term investments, power-related derivatives and our Millstone decommissioning trust. Money market funds are classified as Level 1. Other short-term investments are classified as Level 2. 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, 2010, the fair value of money market funds was $1.7 million, the fair value of short-term investments included in restricted cash was $23.5 million and the fair value of decommissioning trust assets was $5.7 million. The fair value of power-related derivatives was less than $0.1 million at December 31, 2010. See Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk for additional information about power-related derivatives and Part II, Item 8, Note 6 – Fair Value.

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. Derivatives are recorded as current and long-term assets or liabilities depending on the duration of the contracts. Our derivative financial instruments are related to managing our power supply resources to serve our customers, and are not for trading purposes. Contracts that qualify for the normal purchase and sale exception to derivative accounting are not included in derivative assets and liabilities. 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. 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 at December 31, 2010 include annual and monthly 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 6 - Fair Value and Note 16 - Power-Related Derivatives.

Income Taxes The application of income tax law is complex and we are required to make many subjective assumptions and judgments in determining our provision for income taxes, deferred tax assets and liabilities, uncertain tax positions and valuation allowances, if applicable. 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. See Income Tax Matters below.

Other See Part II, Item 8, Note 2 - Summary of Significant Accounting Policies for a discussion of newly adopted accounting policies and recently issued accounting pronouncements.

INCOME TAX MATTERS

Capitalized Repairs Project The Capitalized Repairs Project included the review of 1999 through 2009 property, plant and equipment additions included in Utility Plant on the Consolidated Balance Sheets. The review was performed to identify capitalized additions, which could be expensed, resulting in accelerated income tax deductions. In 2010, as a result of our Capitalized Repairs Project, we recorded a $13.6 million increase in prepayments and a $14.2 increase in deferred income tax liabilities on the Consolidated Balance Sheets. As of year end, we have requested $10.4 million of income tax refunds which we expect to receive in early 2011.

Since these deductions are temporary timing differences, they normally would not affect total income tax expense or the effective tax rate. However, due primarily to a Vermont limitation on the state net operating loss carryforward, we recorded a net increase in combined federal and state GAAP tax expense of $0.7 million. This increase in federal and state income tax expense was subsequently reduced to $0.4 million after the establishment of an uncertain tax position as discussed below.

Casualty Loss Refund Claim Settlement During 2007, we determined that we would file amended federal income tax returns totaling $2.8 million for our Casualty Loss refund claims related to the tax years 2003 through 2006. We concurrently recorded unrecognized tax benefits of $1.2 million. Because of the impact of deferred tax accounting, the disallowance of this item did not affect the effective tax rate. Our Casualty Loss refund claims for the tax years 2003 through 2006 were denied during the IRS audit of these years, and were reviewed and settled by IRS Appeals during 2010. Our settlement allowed 100 percent of the Casualty Loss refund claims for the tax years 2003 through 2005, which totaled $1.9 million plus $0.4 million interest, and allowed none of the 2006 tax year refund claim. In 2010, the remaining Casualty Loss refund unrecognized tax benefit of $1 million was removed from the balance of unrecognized tax benefits. See Uncertain Tax Positions below.

Health Care Reform Legislation On March 23, 2010, the federal PPACA was signed into law. The PPACA is a comprehensive health care reform bill that includes revenue-raising provisions for nearly $400 billion over 10 years through tax increases on high-income individuals, excise taxes on high-cost group health plans, and new fees on selected health-care-related industries. In addition, on March 25, 2010, the Health Care and Education Affordability Reconciliation Act of 2010 was passed into law, which modifies certain provisions of the PPACA.

Together, the legislation repeals the current rule permitting a tax deduction for prescription drug coverage expense under our postretirement medical plan that is actuarially equivalent to that provided under Medicare Part D. This provision is effective for taxable years beginning after December 31, 2012. As required, in March 2010 we recorded an increase of $2.1 million in regulatory assets and an increase of $2.8 million in deferred income taxes on the Consolidated Balance Sheets, resulting in an increase of $0.7 million in income tax expense on the Consolidated Statements of Income, related to postretirement medical expenditures that will not be deductible in the future.

Tax Bonus Depreciation The Small Business Jobs Act of 2010, which became law on September 27, 2010, extended 50 percent bonus depreciation to 2010. In addition, as a result of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which became law on December 17, 2010, the 50 percent bonus depreciation was extended through 2012, and a 100 percent expensing was allowed for property placed in service after September 8, 2010 through 2011. The combined impact of the additional bonus depreciation allowed as a result of these Acts was $6.7 million that was recorded to prepayments and deferred income tax liabilities on the 2010 Consolidated Balance Sheet.

Uncertain Tax Positions During 2010, unrecognized tax benefits were increased by $2.6 million, which is the net of a $3.6 million increase in unrecognized tax benefits established for our Capitalized Repairs deduction and a $1 million decrease in unrecognized tax benefits due to the settlement of our Casualty Loss claims. Due to the impact of deferred tax accounting, the establishment of the $3.6 million Capitalized Repairs unrecognized tax benefit resulted in $0.3 million that would affect the effective tax rate if recognized and the $1 million reduction of the Casualty Loss uncertain tax benefit had no effect on the effective tax rate.

VYNPC Deferred Tax Asset and Valuation Allowance During 2010, based upon FASB income tax accounting guidance, we recorded a $1 million deferred tax asset representing the excess of tax basis over book value for our investment in VYNPC. We also recorded an equal valuation allowance as it is more likely than not that this deferred tax asset will not be realized. There was no impact to the effective tax rate.

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 2010 were $21 million, or $1.66 per diluted share of common stock. This compares to consolidated earnings for 2009 of $20.7 million, or $1.74 per diluted share of common stock and 2008 consolidated earnings of $16.4 million, or $1.52 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 2010 versus 2009 and for 2009 versus 2008. The earnings per diluted share for each variance shown below are non-GAAP measures:

Reconciliation of Earnings Per Diluted Share

	Twelve Months 2010 vs. 2009
2009 Earnings per diluted share	**$1.74**
Year-over-Year Effects on Earnings:	
Higher other operating expenses (excludes exogenous deferral)	(0.18)
Higher purchased power expense	(0.13)
Higher maintenance expenses (excludes exogenous major storms)	(0.11)
Lower other income, net	(0.04)
Higher taxes other than income	(0.04)
Lower operating revenue	(0.01)
Lower transmission expenses	0.43
Higher equity in earnings of affiliates	0.16
Other (includes income tax adjustments, impact of additional common shares and various items)	(0.16)
2010 Earnings per diluted share	**$1.66**

	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**

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**		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Residential	**$146,835**	$139,047	$138,091	**979,922**	981,838	982,966
Commercial	**111,219**	104,001	108,252	**843,156**	825,010	873,192
Industrial	**34,375**	32,597	34,858	**371,591**	364,516	396,741
Other	**1,977**	1,884	1,872	**6,483**	6,398	6,312
Total retail sales	**294,406**	277,529	283,073	**2,201,152**	2,177,762	2,259,211
Resale sales	**37,957**	54,279	48,641	**781,178**	840,536	759,832
Provision for rate refund	**(3,598)**	(1,689)	(296)	**0**	0	0
Other operating revenues	**13,160**	11,979	10,744	**0**	0	0
Total operating revenues	**$341,925**	$342,098	$342,162	**2,982,330**	3,018,298	3,019,043

The average number of retail customers is summarized below:

	2010	**2009**	**2008**
Residential	**136,457**	136,242	136,074
Commercial	**22,672**	22,577	22,407
Industrial	**35**	36	35
Other	**174**	175	175
Total	**159,338**	159,030	158,691

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

	2010 vs. 2009	2009 vs. 2008
Retail sales:		
Volume (mWh)	**$2,674**	($8,937)
Average price due to customer sales mix	**933**	2,532
Average price due to rate increases	**13,270**	861
Subtotal	**16,877**	(5,544)
Resale sales	**(16,322)**	5,638
Provision for rate refund	**(1,909)**	(1,393)
Other operating revenues	**1,181**	1,235
Change in operating revenues	**($173)**	($64)

<u>2010 vs. 2009</u>

Operating revenues decreased by $0.2 million, or less than 0.1 percent, due to the following factors:

- Retail sales increased $16.9 million resulting primarily from a 5.58 percent base rate increase effective January 1, 2010 and the recovery of 2008 major storm costs through the ESAM, in addition to a resurgence of retail load in the second half of 2010.
- Resale sales decreased $16.3 million due to lower 2010 contract prices associated with the sale of our excess energy and a decrease in volumes sold due to the scheduled refueling outages at the Vermont Yankee plant and Millstone Unit #3.

- The provision for rate refund decreased $1.9 million primarily due to over- or under-collections of power, production and transmission costs as defined by the power cost adjustment clause of our alternative regulation plan. This decrease included the unfavorable impact of $3.6 million of net deferrals and refunds in 2010 vs. the unfavorable impact of $1.7 million of net deferrals and refunds in 2009.
- Other operating revenues increased $1.2 million mostly from higher levels of mutual aid to other utilities in 2010 and the sale of renewable energy credits.

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 volumes, partly offset by higher average retail rates and a higher average price due to customer sales mix. Retail sales volumes 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 volumes due to lower retail sales volume and increased output from power producers. Average prices for forward sales increased while average 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 million 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.

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).

	2010 over/(under) 2009		2009 over/(under) 2008	
	Total Variance	**Percent**	**Total Variance**	**Percent**
Purchased power - affiliates and other	**$2,792**	**1.8%**	($7,469)	-4.5%
Production	**378**	**3.3%**	(849)	-6.9%
Transmission - affiliates	**(11,790)**	**-147.3%**	722	9.9%
Transmission - other	**2,853**	**12.0%**	4,948	26.2%
Other operation	**(2,518)**	**-4.3%**	3,416	6.1%
Maintenance	**5,639**	**23.3%**	(3,780)	-13.5%
Depreciation	**649**	**3.8%**	1,261	8.1%
Taxes other than income	**745**	**4.5%**	1,074	6.9%
Income tax expense (benefit)	**2,512**	**49.9%**	155	3.2%
Total operating expenses	**$1,260**	**0.4%**	($522)	-0.2%

Purchased Power - affiliates and other: Power purchases made up 49 percent of total operating expenses in 2010 and 2009 and 51 percent in 2008. 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**		
	2010	2009	2008	**2010**	2009	2008
VYNPC (a)	**$58,715**	$64,017	$57,708	**1,384,551**	1,551,925	1,417,144
Hydro-Québec	**62,971**	63,095	63,670	**963,027**	919,764	937,923
Independent Power Producers	**22,859**	22,559	26,430	**195,325**	202,483	202,193
Subtotal long-term contracts	**144,545**	149,671	147,808	**2,542,903**	2,674,172	2,557,260
Other purchases	**16,146**	7,209	16,877	**174,175**	59,037	165,362
Reserve for loss on power contract	**(1,196)**	(1,196)	(1,196)	**0**	0	0
Nuclear decommissioning	**1,379**	1,312	2,070	**0**	0	0
Other	**(100)**	986	(108)	**0**	0	0
Total purchased power	**$160,774**	$157,982	$165,451	**2,717,078**	2,733,209	2,722,622

(a) Regulatory deferrals of $0.5 million in 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):

	2010 vs. 2009	2009 vs. 2008
VYNPC (a)	**($5,302)**	$6,309
Hydro-Québec	**(124)**	(575)
Independent Power Producers (IPPs)	**300**	(3,871)
Subtotal long-term contracts	**(5,126)**	1,863
Other purchases	**8,937**	(9,668)
Nuclear decommissioning	**67**	(758)
Other	**(1,086)**	1,094
Total purchased power	**$2,792**	($7,469)

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

<u>2010 vs. 2009</u>
Purchased power expense increased $2.8 million, or 1.8 percent, due to the following factors:

- Purchased power costs under long-term contracts decreased $5.1 million in 2010, due primarily to lower output at the Vermont Yankee plant related to an extended scheduled refueling outage, lower capacity costs from Hydro-Québec and decreased purchases from Independent Power Producers.
- Other purchases increased $8.9 million due to higher retail load sourced with increased volumes at higher market prices and the purchase of replacement power for the scheduled refueling outages at Vermont Yankee and Millstone Unit #3.
- Nuclear decommissioning costs increased $0.1 million associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs are based on FERC-approved tariffs.
- Other costs decreased $1.1 million. These Other costs are amortizations and deferrals based on PSB-approved regulatory accounting, including those 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>2009 vs. 2008</u>
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, due primarily to higher Vermont Yankee plant 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 because more power was available from long-term contract sources.
- Nuclear decommissioning costs decreased $0.8 million 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.

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 plant.

There was no significant variance for 2010 versus 2009 or for 2009 versus 2008.

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 VTA, net of 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 decrease of $11.8 million was principally due to higher NOATT reimbursements under the VTA, related to the overall transmission expansion in New England, partially offset by higher charges under the VTA resulting from Transco's capital projects.

Transmission - other: The majority of these expenses are for purchases of regional transmission service under the NOATT and charges for the Phase I and II transmission facilities. The increase of $2.9 million primarily resulted from higher rates and overall transmission expansion in New England.

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 decrease of $2.5 million was primarily due to $1.6 million of lower net regulatory amortizations, largely due to an exogenous effect deferral entry of $4.2 million recorded in 2010, comprised of $3.4 million related to major storms and $0.8 million related to income taxes. We also had $2.1 million of lower reserves for uncollectible accounts, primarily due to a large customer bankruptcy in 2009 and subsequent recovery of $1.1 million in 2010. These decreases were partially offset by $1.2 million of higher employee benefit costs, including higher pension and active employee medical costs, partially offset by lower retiree medical costs.

Maintenance: These expenses are associated with maintaining our electric distribution system and include costs of our jointly owned generation and transmission facilities. The increase of $5.6 million was largely due to higher service restoration costs related to major storms in 2010. We were able to defer $3.4 million of these costs as an exogenous effect deferral as described above in Other operation.

Depreciation: We use the straight-line remaining-life method of depreciation. The increase of $0.6 million was due to a higher level of utility plant assets.

Taxes other than income: This is related primarily to property taxes and payroll taxes. The increase of $0.7 million was largely due to increases in property taxes.

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. The effective combined federal and state income tax rate for 2010 is 41.2 percent compared to 34 percent for 2009 and 39.6 percent for 2008. The 2010 versus 2009 variance includes the impact of the PPACA, as modified by the Health Care and Education Reconciliation Act, which represents 2 percent of the 2010 effective tax rate. This item is considered an exogenous event and is included in the exogenous effects deferral. Also see Part II, Item 8, Note 18 - 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 $0.4 million in 2010, $0.9 million in 2009 and $0.2 million in 2008. 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).

	2010 over/(under) 2009		2009 over/(under) 2008	
	Total Variance	**Percent**	Total Variance	Percent
Equity in earnings of affiliates	**$3,626**	**20.8%**	$1,208	7.4%
Allowance for equity funds during construction	**(42)**	**-26.1%**	(167)	-50.9%
Other income	**308**	**10.5%**	(663)	-18.4%
Other deductions	**(699)**	**44.1%**	3,220	-67.0%
Income tax expense	**(1,477)**	**26.2%**	222	-3.8%
Total other income and deductions	**$1,716**	**14.1%**	$3,820	40.1%

* variance exceeds 100 percent

Equity in earnings of affiliates: These are earnings on our equity investments including VELCO, Transco and VYNPC. The increase of $3.6 million for 2010 versus 2009 is principally due to the $20.8 million investment that we made in Transco in December 2009.

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 increase of $0.3 million for 2010 versus 2009 resulted primarily from higher non-utility revenues and higher interest and dividend income.

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 increase of $0.7 million for 2010 versus 2009 primarily related to changes in the cash surrender value of variable life insurance policies included in our Rabbi Trust. In 2010, there were market losses versus market gains in 2009.

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. The increase of $1.5 million for 2010 versus 2009 resulted primarily from a higher level of earnings from Transco.

CRC provided a $0.5 million unfavorable variance for 2010 versus 2009. This included a $0.2 million valuation allowance that was reversed in 2009 and an unrecognized tax position of $0.3 million recognized in 2009.

Interest Expense Interest expense includes interest on long-term debt, dividends associated with preferred stock subject to mandatory redemption, interest on notes payable and 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).

	2010 over/(under) 2009		2009 over/(under) 2008	
	Total Variance	**Percent**	Total Variance	Percent
Interest on long-term debt	**$24**	**0.2%**	$1,361	13.9%
Other interest	**9**	**2.0%**	(1,460)	-76.5%
Allowance for borrowed funds during construction	**45**	**-42.5%**	13	-10.9%
Total interest expense	**$78**	**0.7%**	($86)	-0.7%

* variance exceeds 100 percent

There was no significant variance for 2010 versus 2009 or for 2009 versus 2008.

POWER SUPPLY MATTERS

Power Supply Management Our power supply portfolio includes a mix of baseload and dispatchable resources. These resources serve our retail electric load requirements and any wholesale sale obligations into which we enter as part of a hedging strategy. We manage our power supply portfolio by attempting to optimize the economic value of these resources and create a balance between our power supplies and load obligations.

Our power supply management philosophy is to strike a balance between cost and risk. We strive to minimize power costs while simultaneously keeping liquidity risks at conservative levels. Risk mitigation strategies are built around minimizing both forward price risks and operational risks while strictly limiting the potential for both our collateral exposure and inefficient deployment of capital. 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 price risks through limited wholesale transactions that hedge market price risk, as discussed below. In addition, we purchased outage insurance, currently effective through early 2011, to help cover unexpected costs of major unplanned Vermont Yankee outages that could cause the plant to curtail deliveries under the current VY PPA. We do not plan to renew the outage insurance. FTR auctions provide us with opportunities to economically hedge our exposure to congestion charges that result from transmission system constraints between generator locations and where load is served. FTRs are awarded to successful bidders in periodic auctions that are administered by ISO-NE.

Our current power forecast suggests we have excess energy supply during 2011. We recently conducted a successful online auction to sell most of our excess energy in the forward market, on a unit-contingent basis, at fixed prices in order to reduce market price volatility and gain a measure of revenue certainty while remaining strictly within potential collateral exposure limits.

Attaining an investment-grade credit rating expanded the available collateral limits with our current counterparties and we have attracted additional counterparties that appear willing to transact with us. However, regardless of collateral limits and available counterparties, we expect to maintain our practice of constraining 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.

	2010	2009	2008
Nuclear	**50%**	55%	50%
Hydro	**40%**	38%	39%
Oil and wood	**4%**	4%	5%
Other	**6%**	3%	6%
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 VY PPA between Entergy-Vermont Yankee and VYNPC. We have one secondary purchaser that receives less than 0.5 percent of our entitlement. See Part II, Item 8, Note 4 – Investments in Affiliates for additional information on the VY PPA.

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. 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.

The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. A refueling outage was completed in May 2010 and estimated incremental costs for replacement power were factored into our 2010 base rates. Our total VYNPC purchases were $58.7 million in 2010, $64 million in 2009 and $57.7 million in 2008.

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, 2010 through March 21, 2011. 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. We do not plan to renew the outage insurance.

Prices under the VY PPA increase $1 per megawatt-hour each calendar year and will be $44 per MWh in 2011 and $45 per MWh in 2012. The VY PPA contains a provision known as the "low market adjuster" that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. Estimated annual purchases are expected to be $65.7 million for 2011 and $16.6 million for 2012 when the contract expires 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.

On June 22, 2010, we, along with GMP, made a claim under the September 6, 2001 VY PPA. The claim is that Entergy-Vermont Yankee breached its obligations under the agreement by failing to detect and remedy the conditions that resulted in cooling tower-related failures at the Vermont Yankee nuclear plant in 2007 and 2008. Those failures caused us and GMP to incur substantial incremental replacement power costs.

We are seeking recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the VY 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 also reviewed the 2007 and 2008 root cause analysis reports by Entergy-Vermont Yankee and a December 22, 2008 reliability assessment provided by Nuclear Safety Associates to the State of Vermont. Entergy-Vermont Yankee disputes our claim. We cannot predict the outcome of this matter at this time.

The VY PPA 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 VY PPA following the uprate. Based on VYNPC's calculations the VYNPC Sponsors should be entitled to slightly more capacity and energy than they have been receiving under the VY PPA since the uprate. 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 the 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 forward market prices as of December 31, 2010, the incremental replacement cost of lost power is estimated to be $14.3 million over the remaining life of the contract. 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 recovery of increased costs 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.

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. The new Vermont Legislature elected on November 2, 2010 could vote differently, although the political makeup of the House and Senate remains largely unchanged. Also, Vermont elected a new governor who advocated as a member of the Vermont Senate and during the gubernatorial campaign that the Vermont Yankee plant should close when its current license expires. While circumstances could change and we expect to engage in a constructive dialogue with the new administration and legislature related to the continued operation of the Vermont Yankee plant, we are unable to predict the outcome at this time.

On March 10, 2011, the NRC voted 4-0 to approve the 20-year license extension through March 21, 2032 requested by Entergy-Vermont Yankee. This approval removes the last federal level regulatory requirement for relicensing of the Vermont Yankee station. However, the Vermont Legislature has not approved the license extension and such approval is considered unlikely at this time. Under Vermont law, in addition to a favorable Vermont legislative vote, the PSB needs to issue a Certificate of Public Good for the plant to continue to operate after March 21, 2012.

Entergy-Vermont Yankee is attempting to overcome legislative concerns, but has also recently intimated that it may challenge the state's authority as it relates to relicensing. In April 2010, we began a new round of negotiations on a new contract. While we rejected Entergy-Vermont Yankee's December 2009 public proposal of contract terms, we continue to exchange information and proposals with them. We cannot predict the outcome of this matter at this time.

Hydro-Québec: We are purchasing power from Hydro-Québec under the 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-Québec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO power contract runs through 2020, but our purchases under the contract end in 2016. The average level of deliveries under the current contract 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. The first 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 31, 2012.

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Québec. The first option was never exercised and expired December 31, 2010. The second gives Hydro-Québec 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 but due to the notice provision there is a maximum remaining application of three times available. To date, Hydro-Québec has not exercised this option. We have determined that this second option is not a derivative 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-Québec, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2010, our obligation is about 47 percent of the total VJO power contract through 2016, and represents approximately $285.7 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 of the event 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 contract in its 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 $335.1 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2011 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-Québec were $63 million in 2010, $63.1 million in 2009 and $63.7 million in 2008. Annual capacity costs decreased by $2.2 million starting November 1, 2009, and that cost reduction will continue for six contract years.

Independent Power Producers: We purchase power from several IPPs. These plants use water or biomass as fuel. Most of the power comes to us through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Our total purchases from IPPs were $22.9 million in 2010, $22.6 million in 2009 and $26.4 million in 2008. Estimated annual purchases are expected to range from $7.7 million to $22.6 million for the years 2011 through 2015. Cost will begin to decrease 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.

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. On April 12, 2010, the stay was lifted and a staggered briefing schedule was proposed, to which DNC has responded with a request to expedite the briefing schedule so that the appeals of all parties can be heard concurrently.

On June 30, 2010, the DOE filed its initial brief in the spent fuel damages litigation. This brief focuses on the costs awarded in connection with Millstone Unit #3. DNC replied to the government's brief in August, 2010. The government's reply brief was filed September 14, 2010 and briefing on the appeal is now complete. Oral argument on the government's appeal occurred before the Federal Circuit on January 12, 2011

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. We expect that our share of a recovery, if any, would be credited to our retail customers.

Other: Other sources of energy are primarily short-term purchases from third parties in New England and the wholesale markets in ISO-NE. On an hourly basis, power is sold or bought through ISO-NE 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-NE, including costs for congestion, line losses, reserves and regulation that vary in part due to changes in the price of energy. The methods for settling the costs of ancillary services are administered by ISO-NE and are subject to change. Congestion and loss charges represent 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-NE has a market mechanism referred to as the FCM to compensate owners of new and existing generation capacity, including demand reduction. ISO-NE 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 currently based on each entity's percentage share of ISO-NE's prior year coincident peak demand and the amount of qualifying capacity in the pool. Net FCM charges in 2010 were about $3.4 million. Based on specified rates through December, 2011, we expect net FCM charges of about $3.2 million.

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 Agreements *New Hydro-Québec Agreement:* On August 12, 2010 we, along with GMP, VPPSA, Vermont Electric Cooperative, Inc., Vermont Marble, Town of Stowe Electric Department, City of Burlington, Vermont Electric Department, Washington Electric Cooperative, Inc and the 13 municipal members of VPPSA (collectively, the "Buyers") entered into an agreement for the purchase of shares of 218 MW to 225 MW of energy and environmental attributes from HQUS commencing on November 1, 2012 and continuing through 2038.

The rights and obligations of the Buyers under the HQUS PPA, including payment of the contract price and indemnification obligations, are several and not joint or joint and several. Therefore, we shall have no responsibility for the obligations, financial or otherwise, of any other party to the HQUS PPA. The parties have also entered into related agreements, including collateral agreements between each Buyer and HQUS, a Hydro-Québec guaranty, an allocation agreement among the Buyers, and an assignment and assumption agreement between us and Vermont Marble, related to the pending acquisition.

The HQUS PPA will replace approximately 65 percent of the existing VJO power contract discussed above, which along with the VY PPA supply the majority of Vermont's current power needs. The VJO power contract and the VY PPA expire within the next several years.

The obligations of HQUS and each Buyer are contingent upon the receipt of certain governmental approvals. On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. The PSB has established a schedule for the docket including technical hearings and final legal briefs in the first quarter of 2011. In the event the HQUS PPA is terminated with respect to any Buyer as a result of such Buyer's failure to receive governmental approvals, each of the other Buyers will have an option to purchase the additional energy.

Under the Agreement, subject to regulatory approval, we would be entitled to purchase an energy quantity of up to 85.4 MW from November 1, 2015 to October 31, 2016; 96.4 MW from November 1, 2016 to October 31, 2020; 98.4 MW from November 1, 2020 to October 31, 2030; 112.1 MW from November 1, 2030 to October 31, 2035; and 26.7 MW from November 1, 2035 to October 31, 2038.

Other Future Power Agreements: As we continue to build and diversify our power portfolio as planned and to comply with state law which establishes goals for including renewable power in our mix, we have recently signed several agreements for clean and competitively priced renewable energy. On September 9, 2010 we agreed to terms for purchasing output over nine years from Iberdrola Renewables' planned Deerfield Wind Project. The agreement was signed by the parties December 13, 2010.

Other recently signed agreements include: two separate agreements to purchase 30.3 percent of the actual output from Granite Reliable Wind project for 20 years beginning April 1, 2012 and an additional 20 percent for 15 years beginning in November 2012; an agreement to purchase the entire 4.99 MW output of Ampersand Gilman Hydro for five years starting April 1, 2012; and 15 MW of around-the-clock energy from J.P. Morgan Ventures Energy for the calendar years 2013 through 2015.

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, 2010, 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, 2010, the total remaining approximate cost for decommissioning and other costs of each plant is as follows: $32.5 million for Maine Yankee, $219.1 million for Connecticut Yankee and $51.2 million for Yankee Atomic. Our share of the remaining obligations amounts to $0.6 million for Maine Yankee, $4.4 million for Connecticut Yankee and $1.8 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 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 greater than Class C 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, Connecticut Yankee claimed $39.7 million and Yankee Atomic claimed $53.9 million in damages through 2001.

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.

A final ruling in favor of the three companies was issued on September 7, 2010. Maine Yankee was awarded $81.7 million, Connecticut Yankee was awarded $39.7 million and Yankee Atomic was awarded $21.2 million. The DOE filed an appeal on November 8, 2010 and the three Yankee companies filed cross-appeals on November 19, 2010. Interest on the judgments does not start to accrue until all appeals have been decided. Our share of the claimed damages of $3.2 million is based on our ownership percentages described above.

The Court of Federal Claims' original decision 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. A trial date has been set for the beginning of August 2011.

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 qualifying 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 TbyO. Our greatest TbyO cost is for our share of the region's high-voltage PTF transmission system through payments made under the NOATT. Our obligation is based on our percentage share of regional peak loads and the total PTF cost of service. The total PTF cost has increased significantly in recent years so that our average 1.8 percent share now yields an annual NOATT charge of over $20 million. While this regional cost-sharing approach greatly reduces our costs related to qualifying Vermont transmission facilities, we pay our share of the costs of all new and existing NOATT-qualifying facilities located throughout 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 classified as 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 the costs of these local facilities is charged through the VTA and is determined by the classification of each project.

Transco has been working with us on a project to solve load-serving and reliability issues related to a 46-kV transmission line extending from Bennington to Brattleboro, Vermont, which we refer to as the Southern Loop. It serves about 25 percent of our load. We initiated a public 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 to improve reliability to the Brattleboro area of the Southern Loop. This included 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 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 $3.7 million a year.

RECENT ENERGY POLICY INITIATIVES

In 2005, the state of Vermont created a renewable energy mandate under SPEED. The primary SPEED goal is that, by January 1, 2012, Vermont utilities produce or purchase energy equal to 5 percent of the 2005 electricity sales, plus sales growth since then, from small-scale solar, wind, hydro and methane energy production.

An additional SPEED goal is that, by 2017, SPEED resources account for 20 percent of Vermont's electricity sales. The SPEED goal is a statewide target, rather than something specific to each utility. We believe we are on pace to achieve the 2012 SPEED targets.

In May, 2009, the Vermont Legislature amended the SPEED law to create a Feed-In Tariff rate for SPEED resources smaller than 2.2 MW in capacity. Feed-In Tariff rates are available for a maximum of 50 MW of capacity. The incremental cost of electricity from Feed-In Tariff projects is to be borne proportionately by all Vermont utilities except Washington Electric Cooperative, which was exempted from the program.

In May 2010, the Vermont Legislature amended the SPEED law to allow existing farm methane generators (including our "Cow Power" generators) to qualify for the Feed-In Tariff. We supported this action.

The 2010 Legislature also repealed a Vermont law that precluded hydroelectric facilities with capacity above 80 MW from being considered as "renewable" resources. While there are no such facilities in Vermont, CVPS purchases power from Hydro-Québec, which does operate facilities larger than 80 MW. We anticipate no immediate impact from this change in policy.

RECENT ACCOUNTING PRONOUNCEMENTS AND TECHNICAL DEVELOPMENTS

Dodd-Frank Act On July 21, 2010, the Dodd-Frank Act was signed into law. While the Dodd-Frank Act has broad implications to the financial services industry, there are some new mandates for public companies that may require changes in corporate governance, compensation, government regulation of the over-the-counter derivatives market, accounting and other areas. The regulations implementing the Dodd-Frank Act have not yet been drafted; however the SEC has begun issuing concept releases under certain provisions. We have already implemented changes related to non-binding shareholder advisory votes on executive compensation and compensation and benefit plan risk assessments.

The Act requires entities to clear most over-the-counter derivatives through regulated central clearing organizations and to trade the derivatives on regulated exchanges. In September 2010, we filed for a waiver of the Dodd-Frank provision that ends the exemption under Section 2(h) of the Commodity Exchange Act. If granted, an extension of time will be provided, exempting us while regulatory rulemaking is taking place and while we evaluate whether our derivatives are subject to the regulations in the Commodity Exchange Act or as adjusted in the Dodd-Frank Act. Even with this exemption, however, we may be subject to reporting requirements pursuant to an interim rule due out soon that will pertain to swap arrangements entered into before the Dodd-Frank Act. We are monitoring and evaluating developments to ensure compliance with any such reporting requirements.

We are uncertain to what degree this legislation may affect our business in the future, but we are evaluating these additional regulatory requirements and the potential impact on our financial statements.

FASB – IASB Convergence The FASB and IASB are working on joint projects to bring U.S. GAAP closer to IFRS, resulting in a major overhaul and reshaping of U.S. GAAP. The FASB's project plan anticipates the completion of many projects in 2011; however, it will consider staggering the effective dates of new standards to ensure an orderly transition to any new requirements. We have not yet evaluated the impact, if any, that the adoption of the new standards may have on our consolidated financial statements.

On February 24, 2010, the SEC issued a statement of 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. During 2011, the SEC is expected to provide an update on their work plan. 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. If so, since we are an accelerated filer, we would be required to adopt IFRS in 2016.

Also, see Part II, Item 8, Note 2 - Summary of Significant Accounting Policies.

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 and throughout 2010. 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.

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 17 - Pension and Postretirement Medical Benefits.

Interest rate changes could also impact the value of the debt securities in our Millstone Unit #3 decommissioning trust and in our Rabbi Trust. At December 31, 2010, the decommissioning trust held debt securities in the amount of $1.3 million and the Rabbi Trust held debt securities in the amount of $2.4 million.

As of December 31, 2010, we had $10.8 million of Industrial Development Revenue bonds outstanding, which have an interest rate that resets monthly. The interest rate amounts borrowed at year end under our $40 million credit facility resets 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, 2010 (dollars in millions).

	Expected Maturity Date						
	2011	2012	2013	2014	2015	Thereafter	Total
Fixed Rate ($)	$11.7	$11.3	$11.3	$11.3	$11.3	$100.0	$156.9
Average Fixed Interest Rate (%)	**6.29%**	6.36%	6.36%	6.36%	6.36%	6.92%	
Variable Rate ($)	**$0.1**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
Average Variable Rate (%)	**0.66%**	0.35%	0.35%	0.35%	0.35%	n/a	

Equity Market Risk: As of December 31, 2010, our pension trust held marketable equity securities in the amount of $61.7 million, our postretirement medical trust funds held marketable equity securities in the amount of $11.7 million, our Millstone Unit #3 decommissioning trust held marketable equity securities of $4.4 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 and 2010. Also see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, and Part II, Item 8, Note 17 - Pension and Postretirement Medical Benefits for additional information.

Wholesale Power Market Price Risk Our most significant power supply contracts are with Hydro-Québec and VYNPC. Combined, these contracts provide the majority of our total 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 19 - Commitments and Contingencies. Summarized information regarding power purchases under these contracts follows.

		2010		2009		2008	
	Expires	**mWh**	**$/mWh**	mWh	$/mWh	mWh	$/mWh
Hydro-Québec (a)	2016	963,027	$65.39	919,764	$68.60	937,923	$67.88
VYNPC (b)	2012	1,384,551	$42.41	1,551,925	$41.25	1,417,144	$40.72

(a) Under the terms of the Hydro-Québec 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 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 PCAM 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, 2009	$269	$134	($149)	$254
Gains and losses (realized and unrealized)				
Included in earnings	3,973	8	0	3,981
Included in Regulatory and other assets/liabilities	(269)	0	149	(120)
Purchases, sales, issuances and net settlements	(3,973)	(114)	0	(4,087)
Total fair value at December 31, 2010	$0	$28	$0	$28
Estimated fair value at December 31, 2010 for changes in projected market price:				
10 percent increase	$0	$3	$0	$3
10 percent decrease	$0	($3)	$0	($3)

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.

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, 2010 and 2009, 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, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements 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 $168,500,000 and $126,742,000 in Transco’s and Velco’s net assets as of December 31, 2010 and 2009, respectively, and of $20,795,000, $17,124,000 and $16,102,000 in Transco’s and Velco’s net income for each of the three years in the period ended December 31, 2010, 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

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, 2010, 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 14, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 14, 2011

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

	For the year ended December 31		
	2010	2009	2008
Operating Revenues	**$341,925**	$342,098	$342,162
Operating Expenses			
Purchased Power - affiliates	**60,094**	65,329	59,778
Purchased Power	**100,680**	92,653	105,673
Production	**11,752**	11,374	12,223
Transmission - affiliates	**(3,788)**	8,002	7,280
Transmission - other	**26,652**	23,799	18,851
Other operation	**56,642**	59,160	55,744
Maintenance	**29,851**	24,212	27,992
Depreciation	**17,570**	16,921	15,660
Taxes other than income	**17,472**	16,727	15,653
Income tax expense	**7,545**	5,033	4,878
Total Operating Expenses	**324,470**	323,210	323,732
Utility Operating Income	**17,455**	18,888	18,430
Other Income			
Equity in earnings of affiliates	**21,098**	17,472	16,264
Allowance for equity funds during construction	**119**	161	328
Other income	**3,243**	2,935	3,598
Other deductions	**(2,284)**	(1,585)	(4,805)
Income tax expense	**(7,117)**	(5,640)	(5,862)
Total Other Income	**15,059**	13,343	9,523
Interest Expense			
Interest on long-term debt	**11,163**	11,139	9,778
Other interest	**458**	449	1,909
Allowance for borrowed funds during construction	**(61)**	(106)	(119)
Total Interest Expense	**11,560**	11,482	11,568
Net Income	**20,954**	20,749	16,385
Dividends declared on preferred stock	**368**	368	368
Earnings available for common stock	**$20,586**	$20,381	$16,017
Per Common Share Data:			
Basic earnings per share	**$1.66**	$1.75	1.53
Diluted earnings per share	**$1.66**	$1.74	1.52
Average shares of common stock outstanding - basic	**12,370,486**	11,660,170	10,458,220
Average shares of common stock outstanding - diluted	**12,405,866**	11,705,518	10,536,131
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)

	2010	2009	2008
Net Income	**$20,954**	$20,749	$16,385
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 $1 in 2010, $2 in 2009 and $1 in 2008	**2**	3	2
Prior service cost, net of income taxes of $(1) in 2010 and $9 in 2009 and 2008	**(2)**	14	13
Transition benefit obligation, net of income taxes of $0 in 2010, 2009 and 2008.	**0**	0	1
Portion reclassified to retained earnings due to change in the benefit measurement date:			
Prior service cost, net of income taxes of $0 in 2010, $0 in 2009 and $2 in 2008	**0**	0	4
Change in funded status of pension, postretirement medical and other benefit plans, net of income taxes of $(16) in 2010, $2 in 2009 and $89 in 2008	**(23)**	2	130
Comprehensive income adjustments	**(23)**	19	150
Total comprehensive income	**$20,931**	$20,768	$16,535

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(dollars in thousands)	For the Years Ended December 31		
Cash flows provided (used) by:	**2010**	2009	2008
OPERATING ACTIVITIES			
Net income	**$20,954**	$20,749	$16,385
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of affiliates	**(21,098)**	(17,472)	(16,264)
Distributions received from affiliates	**14,235**	10,695	10,694
Depreciation	**17,570**	16,921	15,660
Deferred income taxes and investment tax credits	**20,322**	9,633	16,723
Amortization of capital leases	**991**	946	900
Regulatory and other amortization, net	**(3,523)**	(797)	(4,698)
Non-cash employee benefit plan costs	**6,423**	6,275	5,641
Other non-cash expense and (income), net	**5,163**	5,225	6,058
Changes in assets and liabilities:			
Increase in accounts receivable and unbilled revenues	**(4,949)**	(6,520)	(2,454)
(Decrease) increase in accounts payable	**(1,728)**	4,979	(1,740)
(Decrease) increase in accounts payable - affiliates	**(206)**	702	(1,867)
(Increase) decrease in other current assets	**(916)**	4,409	1,456
Decrease (increase) in special deposits and restricted cash for power collateral	**5,370**	(1,734)	(3,580)
Employee benefit plan funding	**(6,493)**	(7,122)	(7,880)
Decrease in other current liabilities	**(867)**	(4,986)	(5,222)
Decrease (increase) in other long-term assets	**640**	132	(2,178)
Increase in other long-term liabilities and other	**1,639**	7	766
Net cash provided by operating activities	**53,527**	42,042	28,400
INVESTING ACTIVITIES			
Construction and plant expenditures	**(33,021)**	(31,413)	(36,835)
Investment in affiliates (Transco)	**(34,918)**	(20,843)	(3,090)
Investments in restricted cash - project fund investments	**(29,767)**	0	0
Reimbursements of restricted cash - project fund investments	**6,288**	0	0
Project reimbursement from DOE	**791**	0	0
Investments in available-for-sale securities	**(1,624)**	(3,761)	(1,475)
Proceeds from sale of available-for-sale securities	**1,337**	3,436	1,201
Other investing activities	**(491)**	(350)	(299)
Net cash used for investing activities	**(91,405)**	(52,931)	(40,498)
FINANCING ACTIVITIES			
Net proceeds from the issuance of common stock	**31,942**	1,655	23,540
Decrease in special deposits for preferred stock mandatory redemption	**1,000**	0	0
Retirement of preferred stock subject to mandatory redemption	**(1,000)**	(1,000)	(1,000)
Common and preferred dividends paid	**(11,712)**	(11,088)	(9,868)
Net proceeds from long-term debt and remarketed bonds	**29,767**	0	63,400
Repayment of long-term debt and remarketed bonds	**0**	(5,450)	(6,400)
Repayment of short-term bridge loan	**0**	0	(53,000)
Proceeds from revolving credit facility and other short-term borrowings	**128,113**	48,501	12,700
Repayments under revolving credit facility and other short-term borrowings	**(137,729)**	(25,190)	(12,700)
Common stock offering and debt issue costs	**(879)**	(210)	(1,054)
Reduction in capital lease and other financing activities	**(1,017)**	(982)	(601)
Net cash provided by financing activities	**38,485**	6,236	15,017
Net Increase (decrease) in cash and cash equivalents	**607**	(4,653)	2,919
Cash and cash equivalents at beginning of the period	**2,069**	6,722	3,803
Cash and cash equivalents at end of the period	**$2,676**	$2,069	$6,722

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, 2010	December 31, 2009
ASSETS		
Utility plant		
Utility plant, at original cost	**$611,746**	$593,211
Less accumulated depreciation	**266,649**	254,858
Utility plant, at original cost, net of accumulated depreciation	**345,097**	338,353
Property under capital leases, net	**4,425**	5,302
Construction work-in-progress	**20,234**	10,235
Nuclear fuel, net	**1,737**	2,190
Total utility plant, net	**371,493**	356,080
Investments and other assets		
Investments in affiliates	**171,514**	129,733
Non-utility property, less accumulated depreciation ($3,164 in 2010 and $3,661 in 2009)	**2,196**	1,900
Millstone decommissioning trust fund	**5,742**	5,082
Restricted cash	**17,581**	0
Other	**7,013**	6,542
Total investments and other assets	**204,046**	143,257
Current assets		
Cash and cash equivalents	**2,676**	2,069
Restricted cash	**5,903**	5,369
Special deposits	**6**	1,007
Accounts receivable, less allowance for uncollectible accounts ($2,649 in 2010 and $3,577 in 2009)	**28,552**	24,597
Accounts receivable - affiliates, less allowance for uncollectible accounts	**314**	40
Unbilled revenues	**21,003**	20,827
Materials and supplies, at average cost	**7,159**	6,219
Prepayments	**15,862**	14,055
Deferred income taxes	**4,501**	3,351
Power-related derivatives	**28**	622
Regulatory assets	**1,924**	0
Other deferred charges - regulatory	**2,078**	0
Other current assets	**1,114**	2,252
Total current assets	**91,120**	80,408
Deferred charges and other assets		
Regulatory assets	**38,552**	46,240
Other deferred charges - regulatory	**2,260**	1,544
Other deferred charges and other assets	**3,275**	4,623
Total deferred charges and other assets	**44,087**	52,407
TOTAL ASSETS	**$710,746**	$632,152

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, 2010	December 31, 2009
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 15,470,217 issued and 13,341,144 outstanding at December 31, 2010 and 13,835,968 issued and 11,706,895 outstanding at December 31, 2009	**$92,821**	$83,016
Other paid-in capital	**94,462**	72,179
Accumulated other comprehensive loss	**(232)**	(209)
Treasury stock, at cost, 2,129,073 shares at December 31, 2010 and 2009	**(48,436)**	(48,436)
Retained earnings	**134,113**	124,873
Total common stock equity	**272,728**	231,423
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Long-term debt	**188,300**	201,611
Capital lease obligations	**3,471**	4,313
Total capitalization	**472,553**	445,401
Current liabilities		
Current portion of preferred stock subject to mandatory redemption	**0**	1,000
Current portion of long-term debt	**20,000**	0
Accounts payable	**8,137**	9,016
Accounts payable - affiliates	**11,835**	12,040
Notes payable	**13,695**	0
Nuclear decommissioning costs	**1,438**	1,443
Power-related derivatives	**0**	219
Other deferred credits - regulatory	**1,108**	0
Other current liabilities	**30,763**	26,450
Total current liabilities	**86,976**	50,168
Deferred credits and other liabilities		
Deferred income taxes	**82,406**	59,215
Deferred investment tax credits	**2,387**	2,642
Nuclear decommissioning costs	**5,383**	7,055
Asset retirement obligations	**3,609**	3,247
Accrued pension and benefit obligations	**32,441**	38,056
Power-related derivatives	**0**	149
Other deferred credits - regulatory	**3,886**	3,888
Other deferred credits and other liabilities	**21,105**	22,331
Total deferred credits and other liabilities	**151,217**	136,583
Commitments and contingencies (Note 19)		
TOTAL CAPITALIZATION AND LIABILITIES	**$710,746**	$632,152

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

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

	Common Stock		Treasury Stock			Accumulated		
	Shares Issued	Amount	Shares	Amount	Other Paid-in Capital	Other Comprehensive Loss, net of tax	Retained Earnings	Total
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, net of tax						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, net of tax						19		19
Common stock issuance					(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**
Net income							20,954	20,954
Other comprehensive income, net of tax						(23)		(23)
Common Stock Issuance, net of issuance costs	1,498,745	8,992			20,621			29,613
Dividend reinvestment plan	69,234	415			972			1,387
Stock options exercised	45,300	272			432			704
Share-based compensation:								
Common & nonvested shares	5,849	35			88			123
Performance share plans	15,121	91			152			243
Dividends declared:								
Common - $0.92 per share							(11,344)	(11,344)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					16			16
Gain (Loss) on capital stock					2		(2)	0
Balance, December 31, 2010	15,470,217	$92,821	(2,129,073)	($48,436)	$94,462	($232)	$134,113	$272,728

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS ORGANIZATION

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-NE, 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 C.V. Realty, Inc., East Barnet and CRC. We have equity ownership interests in VYNPC, VELCO, Transco, Maine Yankee, Connecticut Yankee and Yankee Atomic.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 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, 2010, and the results of operations and cash flows for the years ended December 31, 2010, 2009 and 2008. 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.

Please refer to the Glossary of Terms following the Table of Contents for frequently used abbreviations and acronyms that are found in this report.

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 Note 4 - Investments in Affiliates.

Variable Interest Entities The primary beneficiary of a variable interest entity must consolidate the financial statements of that entity. Transco and VYNPC are variable interest entities; however, we are not the primary beneficiary of either of these entities because we do not control the activities that are most relevant to their operating results. Our maximum exposure to loss is the amount of our equity investments in Transco and VYNPC. See Note 4 - 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 PSB, FERC and the Connecticut Department of Public Utility and Control, 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 should 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, 2010. See Note 9 - Retail Rates and Regulatory Accounting for additional information.

Unregulated Business Our non-regulated business, SmartEnergy Water Heating Services, Inc., is a water heater rental business operating in portions of Vermont and New Hampshire. This non-regulated business is a subsidiary of CRC. Results of operations 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.

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 ISO-NE 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.

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. At December 31, 2010, our allowance for uncollectible accounts was $2.6 million, compared to $3.6 million at December 31, 2009. The change was largely due to a large customer bankruptcy in 2009 and the subsequent recovery of $1.1 million in 2010.

The changes in the allowance for uncollectible accounts were as follows (dollars in thousands):

	Balance at beginning of year	Charged to income and expenses		Deductions		Balance at end of year
2010						
Reserve for uncollectible accounts receivable	$3,577	723	(2)	$1,651	(1)	$2,649
2009						
Reserve for uncollectible accounts receivable	$2,184	3,179	(2)	$1,786	(1)	$3,577
2008						
Reserve for uncollectible accounts receivable	$1,751	$2,473		$2,040	(1)	$2,184
Reserve for uncollectible accounts receivable - affiliates	$48			$48		$0

(1) Write-offs, net of recoveries
(2) In 2009, we provided an allowance of approximately $1M for a commercial customer that declared bankruptcy. We reversed the allowance in 2010 as a result of favorable bankruptcy proceedings and subsequent collection in 2011 of the pre-bankruptcy receivable.

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-NE'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 the 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 2010, 2009 or 2008.

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):

	2010	2009
Wholly owned electric plant in service:		
Distribution	**$319,847**	$308,544
Hydro facilities	**50,692**	48,634
Transmission	**57,998**	57,115
General	**36,393**	34,196
Intangible plant	**6,837**	5,512
Other	**4,695**	4,694
Sub-total wholly owned electric plant in service	**476,462**	458,695
Jointly owned generation and transmission units	**115,748**	115,397
Completed construction	**19,493**	19,076
Held for future use	**43**	43
Utility plant, at original cost	**611,746**	593,211
Accumulated depreciation	**(266,649)**	(254,858)
Property under capital leases, net	**4,425**	5,302
Construction work-in-progress	**20,234**	10,235
Nuclear fuel, net	**1,737**	2,190
Total Utility Plant, net	**$371,493**	$356,080

Property Under Capital Leases We record our commitments with respect to the Hydro-Québec Phase I and II transmission facilities, and other equipment, as capital leases. At December 31, 2010, Property under Capital Leases was comprised of $24.9 million of original cost less $20.5 million of accumulated amortization. At December 31, 2009, Property under Capital Leases was comprised of $24.8 million of original cost less $19.5 million of accumulated amortization See Note 19 - Commitments and Contingencies.

Depreciation We use the straight-line remaining life method of depreciation. The total composite depreciation rate was 2.88 percent of the cost of depreciable utility plant in 2010, 2.85 percent in 2009 and 2.9 percent in 2008.

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 7.7 percent in 2010, 7.8 percent in 2009 and 8.6 percent in 2008. 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 follow (dollars in thousands):

	2010	2009
Asset retirement obligations at January 1	**$3,247**	$3,302
Revisions in estimated cash flows	**246**	(233)
Accretion	**136**	192
Liabilities settled during the period	**(20)**	(14)
Asset retirement obligations at December 31	**$3,609**	$3,247

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 $5.7 million in 2010 and $5.1 million in 2009, and is included in Investments and Other Assets on the Consolidated Balance Sheets.

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 $11.5 million in 2010 and $10.7 million in 2009 are included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Environmental Liabilities We are engaged in various operations and activities that subject us to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. Our policy is to accrue a liability for those sites where costs for remediation, monitoring and other future activities are probable and can be reasonably estimated. See Note 19 - 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. Derivatives are recorded as current and long-term assets or liabilities depending on the duration of the contracts. Our derivative financial instruments are related to managing our power supply resources to serve our customers, and are not for trading purposes. Contracts that qualify for the normal purchase and sale exception to derivative accounting are not included in derivative assets and liabilities. 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. 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. For additional information about power-related derivatives, see Note 6 - Fair Value and Note 16 - Power-Related Derivatives.

Government Grants We recognize government grants when there is reasonable assurance that we will comply with the conditions attached to the grant arrangement and the grant will be received. Government grants are recognized in the Consolidated Statements of Income over the periods in which we recognize the related costs for which the government grant is intended to compensate. When government grants are related to reimbursements of operating expenses, the grants are recognized as a reduction of the related expense in the Consolidated Statements of Income. For government grants related to reimbursements of capital expenditures, the grants are recognized as a reduction of the basis of the asset and recognized in the Consolidated Statements of Income over the estimated useful life of the depreciable asset as reduced depreciation expense.

We record government grants receivable in the Consolidated Balance Sheets in Accounts Receivable. For additional information see Note 9 – Retail Rates and Regulatory Accounting – CVPS SmartPower™.

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the DOE under the ARRA; however, the grant reimbursement is not reflected in our current rates. Grant reimbursements are recorded to a regulatory liability until they are reflected in rates.

Fair Value We use a fair value hierarchy 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 our internal information. Fair value measurements are applicable to financial instruments that are subject to mark-to-market accounting such as our investments in available-for-sale securities, restricted cash, cash equivalents and derivative contracts. See Note 5 – Financial Instruments and Note 6 – 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 Note 10 - 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 Note 17 - Pension and Postretirement Medical Benefits for more information.

Accumulated Other Comprehensive Loss 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, 2008, net of tax of $156	**($228)**
Pension and postretirement medical benefit costs, net	19
Balance at December 31, 2009, net of tax of $142	**($209)**
Pension and postretirement medical benefit costs, net	(23)
Balance at December 31, 2010, net of tax of $158	**($232)**

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.

Special Deposits Special deposits included mandatory sinking fund payments of $1 million in 2010 and 2009 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):

	2010	2009	2008
Interest on temporary investments	**$7**	$61	$257
Non-utility revenue and non-operating rental income	**1,801**	1,862	1,901
Amortization of contributions in aid of construction - tax adder	**938**	975	991
Other interest and dividends	**178**	16	148
Gain on sale of non-utility property	**4**	2	7
Miscellaneous other income	**315**	19	294
Total	**$3,243**	$2,935	$3,598

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

	2010	2009	2008
Supplemental retirement benefits and insurance	**$344**	($249)	$3,041
Non-utility expenses	**1,300**	1,320	1,294
Miscellaneous other deductions	**640**	514	470
Total	**$2,284**	$1,585	$4,805

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

	2010	2009
Taxes	**$14,662**	$12,443
Insurance	**412**	1,055
Miscellaneous	**788**	557
Total	**$15,862**	$14,055

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

	2010	2009
Deferred compensation plans and other	**$2,596**	$2,627
Accrued employee-related costs	**4,660**	5,843
Other taxes and Energy Efficiency Utility	**4,105**	3,306
Cash concentration account - outstanding checks	**2,358**	1,917
Obligation under capital leases	**942**	975
Provision for rate refund	**5,137**	1,520
Miscellaneous accruals	**10,965**	10,262
Total	**$30,763**	$26,450

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):

	2010	2009
Environmental reserve	**$505**	$890
Non-legal removal costs	**11,531**	10,693
Contribution in aid of construction - tax adder	**4,245**	4,705
Reserve for loss on power contract	**4,784**	5,980
Provision for rate refund	**4**	4
Other	**36**	59
Total	**$21,105**	$22,331

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 2010, 2009 and 2008, 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):

	2010	2009	2008
Interest (net of amounts capitalized)	**$11,356**	$11,614	$10,716
Net income taxes (refunded) paid	**($5,703)**	($1,244)	$3,142

Construction and plant expenditures on the Consolidated Statements of Cash Flows reflect actual payments made during the periods. Construction and plant-related expenditures and CVPS SmartPower^{TM} reimbursements are accrued at the end of each reporting period. At December 31, 2010, $1.5 million of construction and plant-related accruals was included in Accounts Payable, and $1.7 million was included in Other Current Liabilities. 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, 2010, Accounts Receivable included $0.3 million representing the capital component of CVPS SmartPower^{TM} reimbursements not yet received from the DOE. We reduced Construction work-in-progress during 2010 for this pending reimbursement.

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

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 an equity investment in and long-term power purchase agreement with VYNPC ("VY PPA"). VYNPC has a power purchase agreement with Entergy-Vermont Yankee, the owner of the Vermont Yankee nuclear plant, and VYNPC purchases 83 percent of the total output of the plant. Under the VY PPA, we purchase our entitlement share of the output of the plant, which is 29 percent of the total plant output. We have evaluated our equity investment and the power purchase agreement with VYNPC under the FASB variable interest accounting guidance and have determined that they both represent variable interests. We are not considered the primary beneficiary of VYNPC; therefore, are not required to consolidate VYNPC because we do not control the activities that are most relevant to the operating results of VYNPC.

We have an equity investment in and receive transmission services from Transco. The transmission services are billed under the 1991 Transmission Agreement ("VTA"). All of the Vermont utilities are parties to the VTA and the VTA requires the Vermont utilities to pay their pro-rata share of Transco's costs, including interest and a fixed rate of return on equity, less the revenues collected under the ISO-NE Open Access Transmission Tariff. We have evaluated our equity investment and the VTA with Transco under the FASB variable interest accounting guidance and have determined that both represent variable interests. We are not considered the primary beneficiary of Transco; therefore, we are not required to consolidate Transco because we do not control the activities that are most relevant to the operating results of Transco.

Our maximum exposure to loss is the amount of our equity investments in Transco and VYNPC. See Note 4 – Investments in Affiliates.

The amended guidance did not have an impact on our financial position, results of operations and cash flows. The guidance became effective for us on January 1, 2010.

NOTE 3 - EARNINGS PER SHARE

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):

	2010	2009	2008
Numerator for basic and diluted EPS:			
Income from continuing operations	**$20,954**	$20,749	$16,385
Dividends declared on preferred stock	**368**	368	368
Net income from continuing operations available for common stock	**$20,586**	$20,381	$16,017
Denominators for basic and diluted EPS:			
Weighted-average basic shares of common stock outstanding	**12,370,486**	11,660,170	10,458,220
Dilutive effect of stock options	**14,388**	20,646	55,525
Dilutive effect of performance shares	**20,992**	24,702	22,386
Weighted-average diluted shares of common stock outstanding	**12,405,866**	11,705,518	10,536,131

Outstanding stock options totaling 44,244 for 2010 and 153,017 for 2009 were excluded from the computation of diluted shares because the exercise prices were above the current average market price of the common shares. All outstanding stock options were included in the computation for 2008 because the exercise prices were below the current average market price of common shares.

Outstanding performance shares totaling 37,330 for 2010 were excluded from the diluted EPS calculation as either the performance share measures were not met or there was an antidilutive impact as of the end of the year as compared to 26,973 shares excluded for 2009 and 12,180 shares excluded for 2008.

NOTE 4 - 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	**2010**	2009	**2010**	2009	2008
Vermont Electric Power Company, Inc.:						
Common stock	47.05%	**$11,875**	$11,726			
Preferred stock	48.03%	**287**	268			
Subtotal		**12,162**	11,994	**$1,473**	$1,776	$1,296
Vermont Transco LLC (a)	36.68%	**156,338**	114,748	**19,322**	15,348	14,806
Vermont Yankee Nuclear Power Corporation	58.85%	**2,875**	2,830	**293**	328	144
Connecticut Yankee Atomic Power Company	2.00%	**43**	65	**0**	13	9
Maine Yankee Atomic Power Company	2.00%	**41**	36	**14**	2	6
Yankee Atomic Electric Company	3.50%	**55**	60	**(4)**	5	3
Total Investments in Affiliates		**$171,514**	$129,733	**$21,098**	$17,472	$16,264

(a) Ownership percentage was 33.35 percent at December 31, 2009.

Undistributed earnings of these affiliates, included in Retained Earnings on our Consolidated Balance Sheets, amounted to $22.1 million at December 31, 2010 and $15.2 million at December 31, 2009. Of these amounts, $21.2 million at December 31, 2010 and $14.5 million at December 31, 2009 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 $34.9 million in Transco in 2010 and $20.8 million in 2009. Our direct ownership interest was 36.68 percent at December 31, 2010 and 33.35 percent at December 31, 2009. 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"). Our total direct and indirect interest in Transco was 41.02 percent at December 31, 2010 and 38.68 percent at December 31, 2009. Transco is a variable interest entity but we are not the primary beneficiary.

Our December 2010 investment in Class A Units included 1,306,400 units related to a new specific facility in the Brattleboro, Vermont area. For 10 years, we are responsible for certain costs associated with the facility. At the end of 10 years, the specific facility will become a Transco common facility that is paid for by all the Vermont utilities receiving transmission service from Transco.

Cash dividends received from VELCO were $1.3 million in 2010, 2009 and 2008. Accounts payable to VELCO were $5.8 million at December 31, 2010 and $5.6 million at December 31, 2009.

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

	2010	2009	2008
Operating revenues	**$104,016**	$93,596	$75,660
Operating income	**$58,544**	$51,903	$40,088
Income before non-controlling interest and income tax	**$50,029**	$42,214	$35,688
Less members' non-controlling interest in income	**45,728**	36,202	30,712
Less income tax	**1,056**	2,338	2,175
Net income	**$3,245**	$3,674	$2,801

	2010	2009
Current assets	**$38,639**	$76,257
Non-current assets	**756,346**	649,187
Total assets	**794,985**	725,444
Less:		
Current liabilities	**47,374**	48,766
Non-current liabilities	**345,869**	355,951
Members' non-controlling interest	**375,945**	295,401
Net assets	**$25,797**	$25,326

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

	2010	2009	2008
Operating revenues	**$103,547**	$93,085	$75,200
Operating income	**$59,884**	$51,903	$40,088
Net income	**$51,849**	$42,623	$35,647

	2010	2009
Current assets	**$34,506**	$71,629
Non-current assets	**746,351**	639,795
Total assets	**780,857**	711,424
Less:		
Current liabilities	**33,175**	34,086
Non-current liabilities	**330,766**	341,869
Mandatorily redeemable membership units	**10,000**	10,000
Net assets	**$406,916**	$325,469

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-NE 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 were a net credit of $3.8 million from Transco in 2010 and charges of $8 million in 2009 and $7.3 million in 2008; these amounts are included in Transmission - affiliates on our Consolidated Statements of Income. There were no accounts payable to Transco at December 31, 2010 and $0.8 million at December 31, 2009. Cash dividends received were $12.7 million in 2010, $9 million in 2009 and $9.1 million in 2008. Accounts receivable from Transco was $0.2 million at December 31, 2010 and there were no accounts receivable from Transco at December 31, 2009.

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 between VYNPC and Entergy-Vermont Yankee ("VY PPA"). Under the VY PPA, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates and, in turn, bills the VY 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 VY 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 Note 19 – Commitments and Contingencies, Long-term Power Purchases.

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):

	2010	2009	2008
Operating revenues	**$168,592**	$183,411	$166,104
Operating income (loss)	**($2,961)**	($2,991)	($543)
Net income	**$497**	$557	$245

	2010	2009
Current assets	**$26,844**	$23,926
Non-current assets	**145,079**	146,957
Total assets	**171,923**	170,883
Less:		
Current liabilities	**17,317**	16,754
Non-current liabilities	**149,721**	149,320
Net assets	**$4,885**	$4,809

VYNPC's revenues shown in the table above include sales to us of $58.7 million in 2010, $64 million in 2009 and $57.7 million in 2008. 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 $5.9 million at December 31, 2010 and $5.6 million at December 31, 2009. Cash dividends received were $0.2 million in 2010, $0.3 million in 2009 and 0.2 million in 2008.

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	$110.2	$32.5	$0.6
Connecticut Yankee	$144.9	$219.1	$4.4
Yankee Atomic	$95.6	$51.2	$1.8

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 2010 dollars for the period 2011 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 2011 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 2010 and 2009 and $0.9 million in 2008. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income.

Plant decommissioning activities were completed in 2005 and the 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 DOE meets its obligation to remove the material from the site.

Connecticut Yankee: Connecticut Yankee's wholesale rates are currently based on a 2010 FERC-approved filing. Our share of decommissioning and other costs amounted to $0.8 million in 2010, 2009 and 2008. 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 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 2010 FERC-approved filing. Based on the approved filing, Yankee Atomic agreed to no change in its revenue requirements from the 2006 FERC-approved settlement. The 2006 approved settlement also provides for reconciling and adjusting future charges based on actual decontamination and dismantling expenses and reporting decommissioning trust fund's actual investment earnings. Our share of decommissioning and other costs amounted to $0.4 million in 2010, 2009 and 2008. 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, Connecticut Yankee claimed $39.7 million and Yankee Atomic claimed $53.9 million in damages through 2001.

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.

A final ruling in favor of the three companies was issued on September 7, 2010. Maine Yankee was awarded $81.7 million, Connecticut Yankee was awarded $39.7 million and Yankee Atomic was awarded $21.2 million. The DOE filed an appeal on November 8, 2010 and the three Yankee companies filed cross-appeals on November 19, 2010. Interest on the judgments does not start to accrue until all appeals have been decided. Our share of the claimed damages of $3.2 million is based on our ownership percentages described above.

The Court of Federal Claims' original decision 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. A trial date has been set for the beginning of August 2011.

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 5 - FINANCIAL INSTRUMENTS

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

	2010		2009	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Power contract derivative assets (includes current portion)	**$28**	**$28**	$622	$622
Power contract derivative liabilities (includes current portion)	**$0**	**$0**	$368	$368
Preferred stock subject to mandatory redemption (includes current portion)	**$0**	**$0**	$1,000	$1,000
First mortgage bonds	**$167,500**	**$188,467**	$167,500	$186,210
Industrial/Economic Development bonds	**$40,800**	**$40,521**	$10,800	$10,800
Credit facility borrowings (includes current portion)	**$13,695**	**$13,695**	$23,311	$23,311

At December 31, 2010, our power-related derivatives consisted of FTRs. In 2010, there were no related unrealized gains or losses. In 2009, related unrealized losses of $0.4 million were recorded as other deferred charges – regulatory on the Consolidated Balance Sheet and related unrealized gains of $0.6 million were recorded as other deferred credits - regulatory. For a discussion of the valuation techniques used for power contract derivatives see Note 6 - Fair Value - Power-related Derivatives below.

The fair values of our first mortgage bonds and fixed rate industrial/economic development bonds 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 as the carrying values of those instruments approximate fair value because of their short duration. The carrying values of our variable rate industrial/economic development bonds approximate fair value since the rates are adjusted at least monthly. The carrying value of our credit facility borrowings approximate fair value since the rates can change daily. The fair value of our cash equivalents and restricted cash are included in Note 6 - 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.

Essentially all of our restricted cash is invested in one issuer. However, the issuer is highly rated and the investment matured on February 1, 2011.

Our accounts receivable are not collateralized. As of December 31, 2010, approximately 8 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 letters of credit or guarantees from their creditworthy 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 and/or letters of credit from certain transmission customers and forward power sale counterparties.

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

NOTE 6 - 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 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 FASB requires 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 FASB 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 and directly held securities in our non-qualified Millstone Decommissioning Trust Fund.

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 commercial paper held in restricted cash and securities not directly held 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 during 2010 and 2009.

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, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities	**$1,587**	**$2,776**		**$4,363**
Marketable debt securities				
Corporate bonds		**350**		**350**
U.S. Government issued debt securities (Agency and Treasury)		**911**		**911**
State and municipal		**38**		**38**
Other		**36**		**36**
Total marketable debt securities	**0**	**1,335**	**0**	**1,335**
Cash equivalents and other		**44**		**44**
Total investments in securities	**1,587**	**4,155**		**5,742**
Restricted cash - long-term		**17,581**		**17,581**
Cash equivalents	**1,653**			**1,653**
Restricted cash		**5,903**		**5,903**
Power-related derivatives - current			**28**	**28**
Total assets	**$3,240**	**$27,639**	**$28**	**$30,907**

	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			$219	$219
Power-related derivatives - long term			149	149
Total liabilities	$0	$0	$368	$368

Millstone Decommissioning Trust Our primary valuation technique to measure the fair value of our nuclear decommissioning trust investments is the market approach. We own a share of the qualified decommissioning fund and cannot validate a publicly quoted price at the qualified fund level. 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.

We recognize transfers in and out of the fair value hierarchy levels at the end of the reporting period. There were no transfers of equity and debt securities within the fair value hierarchy levels during the period ended December 31, 2010.

Cash Equivalents and Restricted Cash The market approach is used to measure the fair values of money market funds and other short-term investments included in cash equivalents and restricted cash. We have the ability to transact our money market funds at the net asset value price per share and can withdraw those funds without a penalty. We are able to obtain actively traded quoted prices for these funds; therefore they are classified as Level 1. We are able to obtain a quoted price for our 60-day commercial paper held in restricted cash; however, the quote was from a less active market. We have concluded that this investment does not qualify for Level 1 and is reflected as Level 2. Cash equivalents are included in cash and cash equivalents on the Consolidated Balance Sheets.

Power-related Derivatives We have historically had three types of derivative assets and liabilities: forward energy contracts, FTRs, and a power-related option contract. At December 31, 2010, our derivatives consisted of FTRs. Our primary valuation technique to measure the fair value of these derivative assets and liabilities is the income approach, which involves determining a present value amount based on estimated future cash flows. However, when circumstances warrant, we may also use alternative approaches as described below to calculate the fair value for each type of derivative. Since many of the valuation inputs are not observable in the market, we have classified our derivative assets and liabilities as Level 3.

To calculate the fair value of forward energy contracts, we typically use a mark-to-market valuation model that includes the following inputs: contract energy prices, forward energy prices, contract volumes and delivery dates, risk-free and credit-adjusted interest rates, counterparty credit ratings and our credit rating.

To calculate the fair value of our FTR contracts we use two different approaches. For FTR contracts entered into with an auction date close to the reporting date, we use the auction clearing prices obtained from ISO-NE, which represents a market approach to determining fair value. Auction clearing prices are used to value all FTRs at December 31 each year. For FTR contract valuations performed at interim reporting dates, we use an internally developed valuation model to estimate the fair values for the remaining portions of annual FTRs. This model includes the following inputs: historic congestion component prices for the applicable locations, historic energy prices, forward energy prices, contract volumes and durations, and the applicable risk-free rate.

To calculate the fair value of our power-related option contract, which expired at December 31, 2010, we used a binomial tree model that included the following inputs: forward energy prices, expected volatility, contract volume, prices and duration, and LIBOR swap rates.

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

	Year ended December 31	
	2010	2009
Balance at Beginning of Period	**$254**	$8,820
Gains and losses (realized and unrealized)		
Included in earnings	**3,981**	23,113
Included in Regulatory and other assets/liabilities	**(120)**	(8,564)
Purchases, sales, issuances and net settlements	**(4,087)**	(23,115)
Balance at December 31	**$28**	$254

At December 31, 2010, there were no realized gains or losses included in earnings attributable to the change in unrealized gains or losses related to derivatives still held at the reporting date. This is due to our regulatory accounting treatment for all power-related derivatives.

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 7 - 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. Regulatory authorities limit our ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments and therefore we lack investing ability and decision-making authority. Accordingly, 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 of 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 2010, we had $0.1 million of realized gains and our realized losses were $0.1 million. The realized losses include $0.1 million of impairments associated with our equity securities; however, there were no permanent impairments or 'credit losses' associated with our debt securities. In addition, there were no non-credit loss impairments to our debt securities in 2010. 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.

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

	As of December 31, 2010			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Marketable equity securities	**$3,075**	**$1,288**		**$4,363**
Marketable debt securities				
Corporate bonds	**333**	**19**	**($2)**	**350**
U.S. Government issued debt securities (Agency and Treasury)	**861**	**53**	**(3)**	**911**
State and municipal	**37**	**1**		**38**
Other	**35**	**1**		**36**
Total marketable debt securities	**1,266**	**74**	**(5)**	**1,335**
Cash equivalents and other	**44**			**44**
Total	**$4,385**	**$1,362**	**($5)**	**$5,742**

	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

Information related to the fair value of debt securities at December 31, 2010 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	$39	$334	$273	$689	$1,335

At December 31, 2010, the fair value of debt securities in an unrealized loss position was $0.2 million. At December 31, 2009, the fair value of debt securities in an unrealized loss position was $0.3 million.

NOTE 8 – RESTRICTED CASH

At December 31, 2010, we had $23.5 million invested in a restricted cash fund comprised of unreimbursed VEDA bond financing proceeds. The investments in this fund consist primarily of commercial paper.

The bond proceeds are held in trust and we access these bond proceeds as reimbursement for capital expenditures made under certain production, transmission, distribution and general facility projects financed by the bond issue.

We recorded $5.9 million of the restricted cash as a current asset on the Consolidated Balance Sheet, which represents expenses paid that are expected to be reimbursed at the next requisition date. We expect to receive reimbursements of the remaining proceeds held in trust by early 2012. See Note 15 – Long-term Debt and Notes Payable, *Industrial/economic development bonds.*

NOTE 9 - 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 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.

Alternative Regulation Plan I: On September 30, 2008, the PSB issued an order approving our alternative regulation plan. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have petitioned for an extension through December, 2013. The plan allows for quarterly PCAM adjustment to reflect changes in power supply and transmission-by-others costs); annual base rate adjustments to reflect changing costs; and an annual ESAM adjustment to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity is 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 ESAM 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 customers in a future period. If the actual return on equity of our regulated business falls between 75 and 125 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and customers. Any earnings shortfall in excess of 125 basis points below the allowed return on equity is fully recovered from customers. As such, the minimum return for our regulated business is 100 basis points below the allowed return. These adjustments are made at the end of each fiscal year.

The ESAM also provides for an exogenous effects provision. Under this provision, we are allowed to defer the unexpected impacts, to the extent these costs exceed $0.6 million, of changes in GAAP, tax laws, FERC or ISO-NE rules and major unplanned operation, maintenance costs, such as those due to major storms and other factors including loss of load not due to variations in heating and cooling temperatures.

On December 31, 2009, the PSB issued its order approving our 2010 base rate filing, which increased rates 5.58 percent, effective for bills rendered beginning January 1, 2010. The allowed rate of return for 2010, calculated in accordance with the plan, was 9.59 percent.

On February 2, 2010, the PSB held a prehearing conference, followed by a workshop, to consider the proposal to amend the non-power cost cap formula of our alternative regulation plan to allow for full cost recovery for new initiatives arising after the effective date of the plan. The DPS supported the proposal, and the 2010 base rate filing increase approved by the PSB included recovery of costs for two new initiatives. On September 3, 2010, the PSB approved the implementation of a new initiatives adder under our alternative regulation plan. In order to qualify for treatment as a new initiative the following criteria must be met: 1) the risk associated with implementing the new initiative is of a nature that is distinct from the ordinary business risk that we assume in discharging our public service obligation, and 2) the costs associated with implementing the new initiative are material. In our 2010 base rate filing we were allowed recovery of $0.2 million for a new initiative that does not meet the PSB criteria. This amount will be returned to customers in 2011.

Using the methodology specified in our alternative regulation plan, we estimated the 2010 return on equity from the regulated portion of our business to be approximately 9 percent. We are required to file this calculation with the PSB by May 1, 2011. No ESAM adjustment was required since this return was within 75 basis points of our 2010 allowed return on equity of 9.59 percent.

In 2010, under the exogenous effects provision of the ESAM, we deferred $4.2 million of costs related to three major storms and tax law changes. On January 31, 2011 we filed with the PSB for recovery of these costs through the ESAM over a 12-month period commencing on July 1, 2011. The PSB has not yet acted on this filing.

The PCAM adjustments for 2010 were calculated to be an over-collection of $0.5 million in the first quarter, an under-collection of $1 million in the second quarter and an over-collection of less than $0.1 million in the third quarter. The over-collection in the first quarter was recorded as current liability and returned to customers over the three months ended September 30, 2010. The under-collection in the second quarter was recorded as a current asset and recovered from customers over the three months ended December 31, 2010. The over-collection in the third quarter was recorded as current liability and will be returned to customers over the three months ended March 31, 2011. We filed PCAM reports, including supporting documentation, each quarter with the PSB identifying the over- and under-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 PCAM adjustment for the fourth quarter of 2010 was an over-collection of $5.2 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending June 30, 2011. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

On February 24, 2011, we filed a request with the PSB to offset the $4.2 million 2010 ESAM deferral against the $5.2 million fourth quarter 2010 PCAM over-collection and return the net refund of $1 million to customers over the three months ending June 30, 2011. The DPS supports our request. The PSB has not yet acted on the request.

On May 1, 2010, we filed our 2009 ESAM calculation using the methodology specified in our alternative regulation plan. The 2009 return on equity from the regulated portion of our business was 9.87 percent. No ESAM adjustment was required in 2009 since this return was within 75 basis points of our 2009 allowed return on equity of 9.77 percent.

The PCAM adjustments for 2009 were calculated to be over-collections of $0.6 million in the first quarter, $0.5 million in the second quarter, $0.6 million in the third quarter and $1 million in the fourth quarter. These over-collections were recorded as current liabilities. We filed PCAM reports, including supporting documentation, each quarter 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 2009 over-collections were returned to customers over the three months ended September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010, respectively.

On November 1, 2010, we submitted two versions of a base rate filing for the rate year beginning January 1, 2011. The first version was for a $21.8 million or 7.46 percent increase in retail rates pursuant to our existing alternative regulation plan, reflecting an allowed ROE of 9.18 percent as a result of the existing ROE adjustment formula.

The second version was for a $24.4 million or an 8.34 percent increase in retail rates, reflecting an allowed ROE of 10.22 percent. This increase was premised upon the PSB approving certain modifications to our existing alternative regulation plan as discussed below in the section titled Alternative Regulation Plan II.

Under our existing 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, less a 1 percent productivity adjustment. The non-power costs associated with the implementation of our Asset Management Plan and our CVPS SmartPower™ project are excluded from the non-power cost cap. Our 2011 non-power costs did not exceed the non-power cost cap.

On December 3, 2010, the DPS recommended that the PSB approve our requested 7.46 percent base rate adjustment under the existing alternative regulation plan with certain conditions.

On December 21, 2010, we filed the ARP MOU between us and the DPS with the PSB regarding certain amendments to the alternative regulation plan including the ROE provisions. As part of the settlement, an agreement was also reached with respect to our 2011 base rate filing. Under the ARP MOU we would be permitted to set our ROE for 2011 at 9.59 percent and implement a 7.67 percent retail rate increase effective with bills rendered January 1, 2011.

On December 29, 2010, the PSB issued an order allowing us to implement a 7.46 percent increase in retail rates, reflecting an allowed ROE of 9.18 percent, effective with bills rendered January 1, 2011. The PSB concluded that there was not sufficient time to conduct a meaningful assessment of the issues raised by the ARP MOU, particularly given the absence of pre-filed supporting testimony. The PSB has opened an investigation into our existing rates in order to assess whether further adjustment is necessary pending its review of the ARP MOU. As discussed below in Alternative Regulation II, the PSB has issued an order concerning our request to modify and extend our existing alternative regulation plan. This order will require consideration in the PSB's investigation into our current rates. At this time we do not expect that this will result in any change to the 7.46 percent rate increase implemented on January 1, 2011.

Alternative Regulation Plan II: On June 30, 2010, we filed a required Alternative Regulation Plan Analysis of Plan Performance with the PSB. This analysis evaluated the effectiveness of the Plan's performance in achieving the goals of Vermont alternative regulation. As described in the evaluation, the implementation of the current plan has helped to advance these goals; however, we also identified concerns and impediments that limit its overall effectiveness in satisfying all of the objectives of Vermont alternative regulation.

To address these concerns, on July 6, 2010 we petitioned the PSB to approve changes to the current plan to: a) extend its duration; b) alter the methodology for implementing the non-power cost cap; and c) reset the allowed ROE as noted above to 10.22 percent. If these changes are approved as initially proposed, the revised plan will expire on December 31, 2013 and the allowed ROE will be reset as of January 1, 2011. Thereafter, the existing annual ROE adjustment methodology would apply for the duration of the plan.

The ARP MOU filed on December 21, 2010 would provide final resolution to all issues regarding our petition to modify and extend our existing alternative regulation plan. Under the ARP MOU, the term of the alternative regulation plan would be extended through 2013 and the allowed ROE would be set at 9.59 percent for 2011. In addition, the ARP MOU provides for a modification to the alternative regulation plan to include a benchmarking mechanism that affects the non-power cost cap for rate years 2012 and 2013. There is also a provision to adjust the non-power cost cap for any cost of service change resulting from an ROE change.

As discussed above, the PSB felt a meaningful assessment of the ARP MOU could not occur before January 1, 2011 and opened an investigation. Technical hearings on the ARP MOU were held on January 5 and 6, 2011. We expect to receive a PSB order in the first quarter of 2011. The PSB may approve, reject or modify the ARP MOU. Based on its ruling on the ARP MOU, the retail rate increase ultimately approved for 2011 may be modified in the investigation. By order dated March 3, 2011, the PSB approved further amendments to the alternative regulation plan that: 1) extend its duration until December 31, 2013; 2) alter the methodology for implementing the non-power-cost cap contained in the plan; 3) reset our allowed ROE; and 4) remove provisions no longer applicable to the provision of our services. These amendments are consistent with the terms of an ARP MOU that was filed with the PSB on December 21, 2010, except that the PSB approved an ROE for us for 2011 of 9.45 percent, rather than the 9.59 percent contained in the ARP MOU. At this time we do not expect there will be any change to the 7.46 percent rate increase implemented on January 1, 2011.

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 November 30, 2009, we filed the 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 reductions 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. By December 31, 2010 we had reduced staffing levels to 517 employees. 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.

On March 31, 2010, the PSB approved the Staffing MOU. The Staffing MOU allows CVPS to recover all reasonable costs associated with the staff reductions in accordance with our new initiatives amendment to the non-power cost cap formula of our alternative regulation plan. As discussed above, for these costs to qualify as a new initiative under the plan they would need to meet the criteria established by the PSB.

CVPS SmartPower™ 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 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.

On April 15, 2010, we signed an agreement with the DOE for our portion of the Smart Grid stimulus grant and project and the agreement became effective April 19, 2010. The agreement includes provisions for funding and other requirements. We are eligible to receive reimbursement of 50 percent of our total project costs incurred since August 6, 2009, up to $31 million. Through December 31, 2010, we incurred $4.7 million of costs, of which $2.4 million were operating expenses and $2.3 million were capital expenditures. We have submitted requests for reimbursement of $2.3 million and have received $1.7 million to date.

On April 7, 2010, we filed the CVPS SmartPower™ MOU with the PSB that included, among other things, the agreement we reached with the DPS on the recovery of costs we will incur due to CVPS SmartPower™ implementation. We received the PSB's order approving the cost recovery principles contained in the CVPS SmartPower™ MOU on August 6, 2010. On September 3, 2010, the PSB recognized the CVPS SmartPower™ plan as an authorized initiative under the new initiative adder discussed above.

The CVPS SmartPower™ MOU allows us to defer the difference between the actual costs included in the approved CVPS SmartPower™ plan and amounts collected through rates. Actual 2010 costs exceeded the amounts collected through rates by less than $0.1 million and were recorded as a regulatory asset.

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the DOE under the ARRA; however, the grant reimbursement was not reflected in our 2010 rates. Grant reimbursements of $1.2 million for 2010 operating costs were recorded as a regulatory liability. Expected grant reimbursements are reflected in 2011 rates.

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 $12.5 million of regulatory assets (total regulatory assets of $40.5 million less pension and postretirement medical costs of $28 million), $4.3 million of other deferred charges - regulatory and $5 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, 2010. We would be required to record pre-tax pension and postretirement costs of $27.5 million to Accumulated Other Comprehensive Loss and $0.5 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, 2010	December 31, 2009
Regulatory assets		
Pension and postretirement medical costs	**$27,959**	$32,033
Nuclear plant dismantling costs	**6,821**	8,498
Nuclear refueling outage costs - Millstone Unit #3	**486**	269
Income taxes	**4,480**	4,389
Asset retirement obligations and other	**730**	1,051
Total Regulatory assets	**40,476**	46,240
Less: Current portion	**1,924**	0
Total Regulatory assets less current portion	**$38,552**	$46,240
Other deferred charges – regulatory		
Vermont Yankee sale costs (tax)	**$0**	$673
Unrealized losses on power-related derivatives	**0**	368
ESAM deferred costs	**4,157**	0
Other	**181**	503
Total Other deferred charges – regulatory	**4,338**	1,544
Less: Current portion	**2,078**	0
Total Other deferred charges - regulatory less current portion	**$2,260**	$1,544
Other deferred credits – regulatory		
Asset retirement obligation - Millstone Unit #3	**$3,009**	$2,497
Vermont Yankee settlements	**0**	183
Unrealized gains on power-related derivatives	**0**	488
CVPS SmartPower™ grant reimbursements	**1,180**	0
Other	**805**	720
Total Other deferred credits – regulatory	**4,994**	3,888
Less: Current Portion	**1,108**	0
Total Other deferred credits - regulatory less current portion	**$3,886**	$3,888

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 Note 17 - 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 Note 4 - Investments in Affiliates. Power-related derivatives are discussed in more detail in Note 6 - Fair Value.

NOTE 10 - 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, 2010 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	137,330	0
Omnibus Stock Plan (a)	450,000	104,369	116,770
Total	1,150,000	284,997	116,770

(a) The 2002 Long-Term Incentive Plan was amended in 2008. The amendments renamed the plan as the 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 both 2010 and 2009 and $0.8 million in 2008. The total income tax benefit recognized in the income statement for share-based compensation was $0.3 million in 2010, $0.4 million in 2009 and $0.3 million in 2008. No compensation costs were capitalized. Cash received from exercise of stock options was $0.6 million in 2010, $0.4 million in 2009 and $1 million in 2008. The tax benefit realized for the tax deductions from option exercises and performance shares issued was $0.2 million in 2010, $0.3 million in 2009 and $0.4 million in 2008. These amounts are included in other paid in capital on the balance sheet.

Currently, any outstanding 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 2010 follows:

	Shares	Weighted Average Exercise Price
Options outstanding and exercisable at January 1	335,297	$18.14
Exercised	(45,300)	$12.24
Granted	0	
Forfeited	0	
Expired	(5,000)	$21.61
Options outstanding and exercisable at December 31	284,997	$19.13

The total intrinsic value of stock options exercised during the last three years was $0.4 million in 2010, $0.3 million in 2009 and $0.6 million in 2008. The aggregate intrinsic value of options outstanding and exercisable as of December 31, 2010 was $0.8 million. The weighted-average remaining contractual life for options outstanding and exercisable as of December 31, 2010 was 2.7 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 2010 follows:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	0	
Granted	9,731	$21.17
Vested	(5,849)	$21.13
Deferred	(3,882)	$21.23
Forfeited	0	
Nonvested at December 31	0	

Common stock is 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 2010, 2009 and 2008. Unearned compensation expense at December 31, 2010 was of a nominal amount.

The weighted-average grant-date fair value of shares granted was $21.17 in 2010, $18.04 in 2009 and $21.18 per share in 2008. The fair value of shares vested totaled approximately $0.1 million in 2010, 2009 and 2008.

Performance Shares Awards under the executive officer long-term incentive program are 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 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 2010 was $20.62 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 2010 was $20.51 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.

	2010	2009	2008
Volatility	**42.00%**	42.30%	32.20%
Risk-free rate of return	**1.53%**	1.09%	2.76%
Dividend yield	**4.75%**	4.07%	3.08%
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 2010 follows:

	Shares	Weighted Average Grant-Date Fair Value
Outstanding at January 1	51,600	$23.35
Contingently granted for the 2010 - 2012 performance cycle	33,500	$20.57
Vested for the 2008 - 2010 performance cycle	(10,850)	$30.40
Forfeited	(10,850)	$28.00
Outstanding at December 31	63,400	$19.87

Compensation expense for performance share plans amounted to $0.6 million in 2010, $0.7 million in 2009 and $0.6 million in 2008. Unrecognized compensation expense for outstanding performance shares based on anticipated performance levels as of December 31, 2010 is approximately $0.5 million and is expected to be recognized over 1.5 years.

At December 31, 2010, the fair value of performance shares that were earned or vested, including dividend equivalents, based on goals that were achieved for the 2008 - 2010 performance cycle and were pending Board of Director approval, was $0.3 million. Board of Director approval was received in February, 2011.

In the first quarter of 2010, a total of 35,155 common shares were issued for the 2007 - 2009 performance cycle, of which the participants withheld receipt of 8,971 shares to satisfy withholding tax obligations. Executive officers can elect to defer the receipt of performance shares. In the first quarter of 2010 a total of 11,063 common shares were deferred. The fair value of shares vested at December 31, 2009 was $0.7 million based on the goals that were achieved for the 2007 - 2009 performance cycle.

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.

NOTE 11 - COMMON STOCK

On November 6, 2009, we filed a Registration Statement with SEC on Form S-3, 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 that allowed us to issue up to $45 million of shares under an “at-the-market” program.

On December 2, 2010, we completed the sale of shares offered under the program. During 2010, we issued 1,498,745 shares for net proceeds of $30 million at an average price of $20.40 per share.

NOTE 12 - 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 13 - PREFERRED AND PREFERENCE STOCK NOT SUBJECT TO MANDATORY REDEMPTION

Preferred and preference stock not subject to mandatory redemption at December 31 follows (dollars in thousands):

	2010	2009
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, 2010, a total of 80,538 shares were outstanding, none of which are subject to mandatory redemption and are listed in the table above. 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 2010, 2009, or 2008.

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, 2010, 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 14 - PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION

We had one series of Preferred Stock, $100 Par Value that was subject to mandatory redemption, 8.3 Percent Series Preferred Stock, with no shares outstanding at December 31, 2010, 10,000 shares and 20,000 shares outstanding at December 31, 2009 and 2008, respectively. All of the provisions described in Note 13 - Preferred and Preference Stock Not Subject to Mandatory Redemption are the same for the 8.3 Percent Series Preferred Stock.

The mandatory redemption requirement for the 8.3 Percent Series Preferred Stock was $1 million (10,000 shares at par value) per annum with an optional non-cumulative $1 million redemption annually. We made our last annual payment of $1 million in 2010 under the mandatory redemption requirements. The 8.3 Percent Series Preferred Stock are now fully redeemed. In the fourth quarter of 2009, we paid our transfer agent $1 million for the final mandatory redemption payment that was effective January 1, 2010. The payment to the transfer agent was 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 zero in 2010 and $0.1 million in 2009.

NOTE 15 - LONG-TERM DEBT AND NOTES PAYABLE

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

	December 31, 2010	December 31, 2009
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
Industrial/Economic Development Bonds		
VIDA Bonds		
Variable, due 2013 (0.35% at December 31, 2010 and 0.75 % at December 31, 2009)	**5,800**	5,800
CDA Bonds		
Variable, due 2015 (0.35% at December 31, 2010 and 0.75% at December 31, 2009)	**5,000**	5,000
VEDA Bonds		
5.00%, due 2020	**30,000**	0
Credit Facility		
$40 million unsecured revolving credit facility (a)		
(0.95% at December 31, 2010 and 0.8875% at December 31, 2009)	**13,695**	23,311
Total long-term debt and notes payable	**221,995**	201,611
Less current amount of long-term debt, due within one year	**(20,000)**	0
Less credit facility, due within one year	**(13,695)**	0
Total long-term debt, less current portion	**$188,300**	$201,611

(a) At December 31, 2010 our outstanding borrowings were classified as Notes Payable

First Mortgage Bonds: Substantially all of our utility property and plant is subject to liens under our First Mortgage Bond indenture. There are no interim sinking fund payments due prior to maturity on any series of first mortgage bonds and all interest rates are fixed. 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.

Industrial/economic development bonds: The CDA and VIDA bonds are tax-exempt, floating rate, monthly demand revenue 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. These two series of bonds are both supported by letters of credit, discussed below.

On December 2, 2010, VEDA issued $30 million of tax-exempt Recovery Zone Facility Bonds, Central Vermont Public Service Corporation Issue, Series 2010 and loaned the proceeds to us under a Loan and Trust Agreement dated December 1, 2010. The bonds carry a fixed interest rate of 5 percent and will mature on December 15, 2020. The proceeds will be used to fund certain capital improvements to our production, transmission, distribution and general facilities. The VEDA bonds are secured by a $30 million issue of first mortgage bonds, Series VV, issued under our Indenture of Mortgage dated as of October 1, 1929, as amended and supplemented. As security, the terms of the Series VV first mortgage bonds mirror those of the VEDA bonds. VEDA has no obligation to pay interest and principal on the VEDA bonds except from proceeds provided by us. There are no interim sinking fund payments due prior to the maturity of the VEDA bonds, and they are not callable prior to maturity at our option. The bond proceeds are held in trust and we access these bond proceeds as reimbursement for capital expenditures made under certain production, transmission, distribution and general facility projects. The trust funds holding the bond proceeds are recorded as restricted cash on the Consolidated Balance Sheets.

Our first mortgage bond and industrial/economic development bond 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 and C.V. Realty, Inc. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions, a breach of warranty or performance of an obligation, or the levy of significant judgments, attachments against our property or insolvency. 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, $20 million in 2011, $0 in 2012, $5.8 million in 2013, $0 in 2014 and $5 million in 2015.

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 the two revenue bond issues totaling $10.8 million, discussed above. We pay an annual fee of 2.4 percent on the letters of credit. 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, 2010, there were no amounts drawn under these letters of credit.

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 that will expire in November 2011. The borrowings under this agreement have been reclassified as Notes Payable on the Consolidated Balance Sheet at December 31, 2010. The Credit Agreement 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. 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 clause (a standard that requires greater adversity than a Material Adverse Change clause). The 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, 2010, there were $13.7 million in loans and $5.5 million in letters of credit outstanding under this credit facility. We had periodic borrowings under this facility during 2010.

We also have a three-year, $15 million unsecured revolving credit facility with a different lending institution pursuant to a Credit Agreement dated December 22, 2010 that expires in December 2013. This facility replaced a 364-day $15 million unsecured revolving credit facility that matured on December 29, 2010. 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 fee of 2.0 percent on the average daily amount of letters of credit outstanding. Various interest rate options exist for amounts borrowed under this facility. This facility does not contain a Material Adverse Effect clause. At December 31, 2010, there were no borrowings or letters of credit outstanding under this credit facility. Through December 31, 2010, we have not used this facility for borrowings or letters of credit.

Long-term Debt Issues: On July 15, 2010, we entered into a commitment to issue $40 million of first mortgage bonds at 5.89 percent on June 15, 2011 in a private placement transaction, pending regulatory approvals. The proceeds will be used to help finance our capital expenditures, debt retirements, investments in Transco and other corporate purposes. These bonds will be issued to one purchaser under a shelf facility that was put in place on February 4, 2011 after receiving regulatory approval on November 30, 2010. The shelf facility allows us to issue up to an additional $60 million of first mortgage bonds directly to the purchaser through December 31, 2012. Neither party has any obligation to issue or purchase the additional $60 million first mortgage bonds available under the shelf facility.

Covenants: Our long-term debt indentures, letters of credit, credit facilities, articles of association 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 two times. At December 31, 2010 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 a 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.

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, $85.8 million of retained earnings was not subject to such restriction at December 31, 2010. 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 16 - 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 one forward power sale contract for 2011. This forward sale was initially structured as a physical sale of excess power. In January 2011 the sale contract was renegotiated as a rate swap that settles financially. We have concluded that neither the original physical sale nor the subsequent rate swap contract are derivatives, since a notional amount does not exist under the terms of either contract.

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. We have not yet entered into a forward purchase contract for the 2011 Vermont Yankee refueling outage. Our power supply forecast shows that in 2012, our load requirements will exceed our energy purchase and production amounts, as certain committed long-term power purchase contracts begin to expire.

On August 12, 2010, we executed a significant long-term power purchase contract with HQUS and we have concluded that this contract meets the “normal purchase, normal sale” exception to derivatives accounting; therefore, we are not required to calculate the fair value of this contract. For additional information on this contract, see Note 19 - Commitments and Contingencies - New Hydro-Québec Agreement.

Several years ago, we entered into the Hydro-Québec Sellback #3 contract, a long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice. The option under this contract expired December 31, 2010. 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-NE. We do not use derivative financial instruments for trading or other purposes.

Accounting for power-related derivatives is discussed in Note 2- Summary of Significant Accounting Policies - Derivative Financial Instruments.

Outstanding power-related derivative contracts at December 31 are as follows:

	MWh (000s)	
	2010	**2009**
Commodity		
Forward Energy Sale Contracts	0	564.1
Forward Energy Purchase Contracts	0	(46.8)
Financial Transmission Rights	1958.3	2067.9
Hydro-Quebec Sellback #3	0	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):

	2010	2009	2008
Net realized gains (losses) reported in operating revenues	**$4,581**	$23,226	($8,596)
Net realized gains (losses) reported in purchased power	**(600)**	(113)	(10)
Net realized gains (losses) reported in earnings	**$3,981**	$23,113	($8,606)

Realized gains and losses on derivative instruments are conveyed to or recovered from customers through the PCAM and have no net 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 Note 6 - 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. We have no derivative instruments with credit-risk-related contingent features that were in a liability position on December 31, 2010. For information concerning performance assurance, see Note 19 - Commitments and Contingencies - Performance Assurance.

NOTE 17 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

We have a qualified, non-contributory, defined-benefit pension plan covering unionized and non-unionized employees hired prior to April 1, 2010, 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.

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. The pension plan described above was closed to employees hired after the conversion date. All employees hired after the conversion date are now 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 pension benefits described above will remain in effect. In addition, employees hired before the conversion date 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 was 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.

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. Pre-age 65 retirees participate in plan options similar to active employees. Post-age 65 retirees 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 was enhanced with sharing of one-half of the Medicare Part D subsidy that we received. Under this enhancement, we 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 $0.8 million in 2010 and $1.7 million in 2009.

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, 2010 and 2009 measurement dates follow (dollars in thousands):

	Pension Benefits		Postretirement Medical Benefits	
	2010	2009	**2010**	2009
Benefit obligation at beginning of fiscal year	**$116,958**	$106,236	**$28,861**	$28,553
Service cost	**4,103**	3,783	**912**	710
Interest cost	**7,016**	6,608	**1,580**	1,712
Plan participants' contributions	**0**	0	**606**	639
Actuarial loss (gain)	**7,223**	3,014	**(4,706)**	(1,119)
Gross benefits paid	**(6,798)**	(3,934)	**(2,242)**	(2,298)
less: federal subsidy on benefits paid	**0**	0	**230**	209
Plan amendments	**0**	1,251	**0**	455
Benefit obligation at fiscal year end	**$128,502**	$116,958	**$25,241**	$28,861
Accumulated obligation as of measurement date (December 31)	**$105,930**	$96,604	n/a	n/a

The reduction in our accumulated postretirement benefit obligation due to the impact of the Medicare Part D subsidy was $0.5 million for 2010 and $5.4 million for 2009.

The present value of future contributions from Postretirement Plan participants was $31.7 million for 2010 and $36 million for 2009.

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at the December 31 measurement date for 2010 and 2009 are shown in the table that follows. The selection methodology used in determining discount rates includes portfolios of "Aa"-rated 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	
	2010	2009	**2010**	2009
Discount rates	**5.75%**	6.00%	**5.25%**	5.50%
Rate of increase in future compensation levels	**4.25%**	4.25%	**4.25%**	4.25%

For measurement purposes, an 8.5 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2010, 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 estimated 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, 2010	$1,873	($1,587)
Effect on aggregate service and interest costs	$223	($185)

Asset Allocation The asset allocations at the measurement date for 2010 and 2009, and the target allocation for 2011, by asset category, are as follows:

	Pension Plan			Postretirement Medical Plan		
	2011 Target	**2010**	2009	**2011 Target**	**2010**	2009
Equity securities	**54%**	58%	62%	**60%**	62%	60%
Debt securities	**46%**	42%	38%	**40%**	38%	38%
Other	**0%**	0%	0%	**0%**	0%	2%
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, maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 54 percent of plan assets be invested in equity securities and 46 percent of plan assets be invested in debt securities. The debt securities are primarily comprised of long-duration bonds to match changes in plan liabilities.

Our postretirement medical benefit plan investment policy seeks to achieve sufficient funding levels to meet future benefit obligations to participants and minimize near-term cost volatility. 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 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, 2010 and 2009 measurement dates follow (dollars in thousands):

	Pension Plan		Postretirement Medical Plan	
	2010	2009	**2010**	2009
Fair value of plan assets at beginning of fiscal year	**$97,205**	$79,178	**$15,027**	$9,249
Actual return on plan assets	**13,731**	19,535	**2,239**	3,381
Employer contributions	**3,296**	2,426	**2,777**	4,057
Plan participants' contributions	**0**	0	**606**	638
Gross benefits paid	**(6,798)**	(3,934)	**(2,242)**	(2,298)
Fair value of assets at fiscal year end	**$107,434**	$97,205	**$18,407**	$15,027

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

	Pension Plan		Postretirement Medical Plan	
	2010	2009	**2010**	2009
Fair value of assets	**$107,434**	$97,205	**$18,407**	$15,027
Benefit obligation	**(128,502)**	(116,958)	**(25,241)**	(28,861)
Funded Status	**($21,068)**	($19,753)	**($6,834)**	($13,834)

The decrease in the Pension Plan funded status of $1.3 million for 2010 versus 2009 resulted from a increase of $10.2 million in the fair value of assets as shown in the table above, and an increase of $11.5 million in the benefit obligation, primarily due to actual gains on plan assets as shown in the tables above and changes in actuarial assumptions including the discount rate.

The increase in the Postretirement Medical Plan funded status of $7 million for 2010 versus 2009 resulted from an increase of $3.4 million in the fair value of assets as shown in the table above, and a decrease of $3.6 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 Note 6 - 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 2011	Pension Plan Fair Value as of December 31, 2010 Level 1	Level 2	Level 3	Total
Marketable equity securities					
U.S. Large cap	**31%**	**$34,893**			**$34,893**
U.S. Small and mid cap	**5%**	**5,645**			**5,645**
International	**18%**	**21,209**			**21,209**
Other					**0**
Total marketable equity securities	**54%**	**$61,747**	**0**	**0**	**$61,747**
Marketable debt securities					
Corporate bonds	**33%**	**$20,958**			**$20,958**
U.S. Government issued debt securities		**8,058**			**8,058**
U.S. Agency debt		**666**			**666**
Non-corporate		**1,774**			**1,774**
High yield debt	**10%**	**10,640**			**10,640**
Emerging markets debt	**3%**	**3,100**			**3,100**
Other		**282**			**282**
Total marketable debt securities	**46%**	**$45,478**	**0**	**0**	**$45,478**
Cash and cash equivalents		**0**			**0**
Other		**209**			**209**
Total	**100%**	**$107,434**	**$0**	**$0**	**$107,434**

	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					
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 2011	**Postretirement Medical Plan Fair Value as of December 31, 2010 Level 1**	**Level 2**	**Level 3**	**Total**
Marketable equity securities					
U. S. Large cap	**35%**	**$6,777**			**$6,777**
U. S. Small and mid cap	**9%**	**1,874**			**1,874**
International	**16%**	**3,006**			**3,006**
Other					**$0**
Total marketable equity securities	**60%**	**11,657**	**0**	**0**	**11,657**
Marketable debt securities					
Corporate bonds	**35%**	**1,509**			**1,509**
U.S. Government issued debt securities		**777**			**777**
U.S. Agency debt		**1,964**			**1,964**
State and municipal		**26**			**26**
High yield debt	**5%**	**1,009**			**1,009**
Other		**1,923**			**1,923**
Total marketable debt securities	**40%**	**7,208**	**0**	**0**	**7,208**
Cash and cash equivalents					**0**
Other		**26**			**26**
Total Fair Value	**100%**	**$18,891**	**0**	**0**	**$18,891**
Less amounts due from Trust to CVPS at December 31, 2010					**(484)**
Net Plan Assets					**$18,407**

	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					
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		**Postretirement Medical Benefits**	
	2010	2009	**2010**	2009
Current liability	**$0**	$0	**($179)**	($201)
Non-current liability	**(21,068)**	(19,753)	**(6,655)**	(13,633)
Total	**($21,068)**	($19,753)	**($6,834)**	($13,834)

At December 31, 2010, 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 2011.

Amounts recognized in Regulatory Assets and Accumulated Other Comprehensive Loss The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2010 consisted of (dollars in thousands):

	Pension Benefits			**Postretirement Medical Benefits**		
	Regulatory Asset	**AOCL**	**Total**	**Regulatory Asset**	**AOCL**	**Total**
Net actuarial loss	$18,429	$59	$18,488	$4,190	$13	$4,203
Prior service cost	2,572	8	2,580	1,791	6	1,797
Transition obligation	0	0	0	447	1	448
Net amount recognized	$21,001	$67	$21,068	$6,428	$20	$6,448

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			Postretirement Medical Benefits		
	Regulatory Asset	AOCL	Total	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

Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets and Other Comprehensive Income Components of pre-tax changes from 2009 to 2010 were as follows (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	AOCL	Total	Regulatory Asset	AOCL	Total
Amounts amortized during the year						
Net transition obligation	$0	$0	$0	($255)	($1)	($256)
Net prior service cost	(427)	(1)	(428)	(279)	0	(279)
Net loss	0	0	0	(966)	(3)	(969)
Amounts arising during the year						
*Net loss (gain)	1,735	8	1,743	(5,703)	(17)	(5,720)
Net amount recognized	$1,308	$7	$1,315	($7,203)	($21)	($7,224)

*includes loss/(gain) of $21,379 related to Medicare Part D subsidy receipts in 2010, lower/(higher) than expected

Components of pre-tax changes from 2008 to 2009 were as follows (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	AOCL	Total	Regulatory Asset	AOCL	Total
Amounts amortized during the year						
Net transition obligation	$0	$0	$0	($255)	($1)	($256)
Net prior service cost	(341)	(1)	(342)	(278)	(1)	(279)
Net loss	0	0	0	(1,511)	(5)	(1,516)
Amounts arising during the year						
Net prior service cost	1,247	4	1,251	454	1	455
Net gain	(8,189)	(25)	(8,214)	(3,703)	(11)	(3,714)
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		
	2010	2009	2008	**2010**	2009	2008
Service cost	**$4,103**	$3,783	$3,291	**$912**	$710	$621
Interest cost	**7,016**	6,608	6,092	**1,580**	1,712	1,611
Expected return on plan assets	**(8,251)**	(8,306)	(7,323)	**(1,205)**	(785)	(1,067)
Amortization of net actuarial loss	**0**	0	0	**969**	1,516	1,052
Amortization of prior service cost	**428**	342	389	**279**	279	0
Amortization of transition obligation	**0**	0	0	**256**	256	256
Net periodic benefit cost	**3,296**	2,427	2,449	**2,791**	3,688	2,473
Less amounts capitalized	**678**	311	405	**574**	473	409
Net benefit costs expensed	**$2,618**	$2,116	$2,044	**$2,217**	$3,215	$2,064

Benefit Cost Assumptions Weighted average assumptions are used to determine our annual benefit costs.

	Pension Benefits			Postretirement Medical Benefits		
	2010	2009	2008	**2010**	2009	2008
Weighted-average discount rates	**6.00%**	6.15%	6.30%	**5.50%**	6.05%	6.15%
Expected long-term return on assets	**7.85%**	7.85%	8.25%	**7.85%**	7.85%	8.25%
Rate of increase in future compensation levels	**4.25%**	4.25%	4.25%	**4.25%**	4.25%	4.25%

2011 Cost Amortizations: The estimated amounts that will be amortized from regulatory assets and accumulated other comprehensive income into net periodic benefit cost in 2011 are as follows (dollars in thousands):

	Pension Benefits	Postretirement Medical Benefits
Actuarial loss	$240	$203
Prior service cost	414	278
Transition benefit obligation	0	256
Total	$654	$737

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 2010 pension and postretirement medical benefit expenses. The expected long-term rate of return on assets used to calculate these expenses for 2011 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.

The Pension Plan assets earned a return, net of fees, of 14.6 percent in 2010 and 25.2 percent in 2009. Due to historic underperformance in global financial markets, the Pension Plan assets realized a loss of 12.2 percent, net of fees for the Plan year ended December 31, 2008.

Trust Fund Contributions The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. In 2010, we contributed $3.3 million to the pension trust fund and $2.8 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 2011, approximately $8.6 million will be paid from the Pension Plan trust fund, and $2.1 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
Expected Contributions During 2011			
Employer	$4,100	$1,500	
Plan participants	n/a	$699	
Expected Benefit Payments			
2011	$8,564	$2,080	$234
2012	13,122	2,159	250
2013	8,406	2,277	267
2014	10,513	2,364	285
2015	10,854	2,360	313
2016 - 2020	53,954	11,983	1,871

As of December 31, 2010, the Medicare Part D subsidy reduced the postretirement benefit obligation by $0.5 million and reduced the 2010 net periodic benefit cost by $0.8 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 2010, the year-end post-employment medical benefit obligation was $1.2 million, of which $1 million was recorded as Accrued pension and benefit obligations and $0.2 million was recorded as Other current liabilities. For 2009, the year-end post-employment benefit obligation was $1.2 million, of which $1.1 million was recorded as Accrued pension and 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 $0.2 million in 2010, $(0.1) million in 2009 and $0.1 million in 2008.

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. Eligible employees are at all times vested 100 percent in their pre-tax and post-tax contribution account and in their matching employer contribution. As discussed above, additional changes to our 401(k) Savings Plan became effective on April 1, 2010. Our matching contributions amounted to $1.7 million in 2010, $1.5 million in 2009 and $1.4 million in 2008.

Other Benefits: We also provide a SERP to certain of our executive officers. The SERP is designed to supplement the retirement benefits available through our qualified Pension Plan and for officers newly hired after April 1, 2010 to supplement the retirement benefits available through our defined contribution plan.

For 2010, the accumulated year-end SERP benefit obligation, based on a discount rate of 4.95 percent, was $3.6 million, of which $3.5 million was recorded as Accrued pension and benefit obligations and $0.1 million was recorded as Other current liabilities in the Consolidated Balance Sheets. The 2009 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 accumulated SERP benefit obligation included a comprehensive gain of $0.1 million in 2010. The accumulated SERP benefit obligation included an immaterial comprehensive loss in 2009 and a comprehensive gain of $0.3 million in 2008. The pre-tax SERP benefit costs charged to expense totaled $0.2 million in 2010 and $0.3 million in both 2009 and 2008.

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 $7 million in 2010 and $6.5 million in 2009. Rabbi Trust expenses, including changes in cash surrender value, are included in Other deductions on our Consolidated Statements of Income. The pre-tax amounts charged (credited) to expense were $0.1 million for 2010, ($0.6) million for 2009 and $2.6 million for 2008.

NOTE 18 - INCOME TAXES

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

	2010	2009	2008
Federal:			
Current	**($5,268)**	$250	($6,636)
Deferred	**15,645**	9,003	15,398
Investment tax credits, net	**(255)**	(320)	(379)
Valuation allowance	**797**	99	(99)
	10,919	9,032	8,284
State:			
Current	**(392)**	790	519
Deferred	**3,924**	1,134	1,654
Valuation allowance	**211**	(283)	283
	3,743	1,641	2,456
Total federal and state income taxes	**$14,662**	$10,673	$10,740

Federal and state income taxes charged to:			
Operating expenses	**$7,545**	$5,033	$4,878
Other income	**7,117**	5,640	5,862
	$14,662	$10,673	$10,740

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):

	2010	2009	2008
Income before income tax	**$35,616**	$31,423	$27,125
Federal statutory rate	35.0%	35.0%	35.0%
Federal statutory tax expense	**12,466**	10,998	9,494
Increase (benefit) in taxes resulting from:			
Dividend received deduction	**(435)**	(584)	(408)
State income taxes net of federal tax benefit	**2,339**	773	1,695
Investment credit amortization	**(255)**	(320)	(379)
Renewable Electricity Credit		(233)	(249)
AFUDC equity depreciation	**112**	109	109
Life insurance	**(221)**	(451)	680
Medicare Part D	**653**	(402)	(157)
Domestic production activities deduction	**(113)**	0	0
Valuation allowance	**797**	99	(99)
VY Investment	**(811)**	0	0
Other	**130**	684	54
Total income tax expense (benefit)	**$14,662**	$10,673	$10,740
Effective combined federal and state income tax rate	41.2%	34.0%	39.6%

Capitalized Repairs Project: The Capitalized Repairs Project included the review of 1999 through 2009 property, plant and equipment additions included in Utility Plant on the Consolidated Balance Sheets. The review was performed to identify capitalized additions, which now result in accelerated income tax deductions. In 2010, as a result of our Capitalized Repairs Project, excluding the impact of the related unrecorded tax benefit, we recorded $13.6 million to prepayments and $14.2 million to deferred income tax liabilities on the Consolidated Balance Sheets.

Casualty Loss Refund Claim Settlement: Our Casualty Loss refund claims for the tax years 2003 through 2006, which were previously denied during the IRS audit of these years, were reviewed and settled by IRS Appeals during 2010. Our settlement allowed 100 percent of the Casualty Loss refund claims for the tax years 2003 through 2005, which totaled $1.9 million plus $0.4 million interest, and allowed none of the 2006 tax year refund claim. In 2010, the remaining Casualty Loss refund unrecognized tax benefit of $1 million was removed from the balance of unrecognized tax benefits.

Uncertain Tax Positions: We follow FASB's guidance and methodology for estimating and reporting amounts associated with uncertain tax positions.

A reconciliation of the beginning and ending amount of gross unrecognized tax benefits follows (dollars in thousands):

	2010	2009	2008
Balance at January 1	**$987**	$1,662	$1,870
Reductions from lapse of the statute of limitations		(556)	(74)
Reductions due to the passage of time/other	**(56)**	(119)	(134)
Settlements	**(931)**		
Gross amount of increase as a result of current year tax positions	**3,688**		0
Balance at December 31	**$3,688**	$987	$1,662

During 2010, unrecognized tax benefits were increased by $ 2.6 million which, due to the impact of deferred tax accounting, resulted in $0.3 million that would affect the effective tax rate if recognized. The $2.6 million increase in unrecognized tax benefits is the net of a $3.6 million increase in unrecognized tax benefits established for our Capitalized Repairs deduction and a $1 million decrease in unrecognized tax benefits due to the settlement of our Casualty Loss claims.

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.

We recognize interest related to unrecognized tax benefits as interest expense and penalties are recorded as other deductions. There was no interest expense in 2010, a $0.1 million reversal of previously recorded interest expense in 2009 and less than $0.1 million of interest expense in 2008. There was no accrued interest related to unrecognized tax benefits at December 31, 2010 and 2009.

The 2004 through 2006 tax years, although audited by the IRS, and the 2007 through 2009 tax years remain open to examination. The 2008 tax year is currently under examination by the IRS. For state tax purposes the 2007 through 2009 tax years remain open to examination by the states of New York, New Hampshire, Maine, Connecticut and Vermont.

Valuation Allowance: 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. During 2010, based upon FASB income tax guidance, we recorded a $1 million deferred tax asset representing the excess of tax basis over book value for our investment in VYNPC. We also recorded an equal valuation allowance as it is more likely than not that this deferred tax asset will not be realized. There was no tax impact for this transaction. 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. During 2009 we obtained information that led us to conclude it was more likely than not that the capital loss will be utilized during the five-year carryforward period and we reversed the valuation allowance.

Health Care Legislation: On March 23, 2010, the PPACA was signed into law. The PPACA is a comprehensive health care reform bill that includes revenue-raising provisions for nearly $400 billion over 10 years through tax increases on high-income individuals, excise taxes on high-cost group health plans, and new fees on selected health-care-related industries. In addition, on March 25, 2010, the Health Care and Education Affordability Reconciliation Act of 2010 was passed into law, which modifies certain provisions of the PPACA.

Together, the legislation repeals the current rule permitting a tax deduction for prescription drug coverage expense under our postretirement medical plan that is actuarially equivalent to that provided under Medicare Part D. This provision is effective for taxable years beginning after December 31, 2012. As required, in 2010 we recorded an increase of $2.1 million in regulatory assets and an increase of $2.8 million in deferred income taxes liabilities on the Consolidated Balance Sheets, resulting in an increase of $0.7 million in income tax expense on the Consolidated Statements of Income, related to postretirement medical expenditures that will not be deductible in the future. This legislative change is considered an exogenous event and is included in the exogenous effects deferral. See Note 9 – Retail Rates and Regulatory Accounting for additional information.

Tax Bonus Depreciation: The Small Business Jobs Act of 2010, which became law on September 27, 2010, extended 50 percent bonus depreciation to 2010. In addition, as a result of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which became law on December 17, 2010, the 50 percent bonus depreciation was extended through 2012, and a 100 percent expensing was allowed for property placed in service after September 8, 2010 through 2011. The combined impact of the additional bonus depreciation allowed as a result of these Acts was $6.7 million that was recorded to prepayments and deferred income tax liabilities on the current year Consolidated Balance Sheet. These legislative changes are considered exogenous events and are included in the exogenous effects deferral. See Note 9 - Retail Rates and Regulatory Accounting for additional information.

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):

	2010	2009
Deferred tax assets - current		
Reserves for uncollectible accounts	**$1,073**	$1,450
Deferred compensation and pension	**906**	938
Environmental costs accrual	**11**	274
Loss on terminated power contract	**485**	485
Active medical accrual	**270**	332
Self insurance reserve	**472**	433
PCAM	**2,086**	616
Smart Grid	**388**	0
Other accruals	**407**	446
Total deferred tax assets - current	**6,098**	4,974
Deferred tax liabilities - current		
Property tax accruals	**397**	382
Prepaid insurance	**150**	400
Derivative instruments	**11**	252
ESAM	**842**	589
Other accruals	**197**	0
Total deferred tax liabilities - current	**1,597**	1,623
Net deferred tax assets - current	**$4,501**	$3,351
Deferred tax assets - long term		
Accruals and other reserves not currently deductible	**$1,953**	$2,042
Millstone decommissioning costs	**2,327**	2,060
Contributions in aid of construction	**1,720**	1,907
Loss on terminated power contract	**1,939**	2,423
Derivative instruments	**0**	258
Investments	**1,008**	0
Pension and postretirement medical liability	**10,926**	15,553
Gross deferred tax assets - long term	**19,873**	24,243
Less valuation allowance	**(1,008)**	0
Total deferred tax assets - long-term	**18,865**	24,243
Deferred tax liabilities - long term		
Property, plant and equipment	**67,388**	53,785
Benefits - regulatory asset	**11,330**	12,981
Investments	**19,226**	13,338
Other	**3,327**	3,354
Total deferred tax liabilities - long term	**101,271**	83,458
Net deferred tax liabilities - long term	**82,406**	**59,215**
Net deferred tax liabilities	**$77,905**	**$55,864**

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

	2010	2009
Total deferred tax liabilities - current and long-term	**$102,868**	$85,081
Less total deferred tax assets - current and long-term	**24,963**	29,217
Net deferred tax liabilities	**$77,905**	$55,864

NOTE 19 - COMMITMENTS AND CONTINGENCIES

Long-Term Power Purchases *Vermont Yankee:* We are purchasing our entitlement share of Vermont Yankee plant output through the VY PPA between Entergy-Vermont Yankee and VYNPC. We have one secondary purchaser that receives less than 0.5 percent of our entitlement. See Note 4 – Investments in Affiliates for additional information on the VY PPA.

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. 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.

The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. A refueling outage was completed in May 2010 and estimated incremental costs for replacement power were factored into our 2010 base rates. Our total VYNPC purchases were $58.7 million in 2010, $64 million in 2009 and $57.7 million in 2008.

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, 2010 through March 21, 2011. 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. We do not plan to renew the outage insurance.

Prices under the VY PPA increase $1 per megawatt-hour each calendar year and will be $44 per MWh in 2011 and $45 per MWh in 2012. The VY PPA contains a provision known as the “low market adjuster” that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. Estimated annual purchases are expected to be $65.7 million for 2011 and $16.6 million for 2012 when the contract expires in March. A summary of the VY PPA, including the actual amount for 2010 and the estimated average amounts for 2011 and 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.

		Estimated Average	
	2010	**2011**	**2012**
Average capacity acquired	180 MW	180 MW	180 MW
Share of VYNPC entitlement	34.80%	34.80%	34.80%
Annual energy charge per mWh	$43.13	$44.43	$45.41
Average total cost per mWh	$42.41	$44.80	$47.58
Contract period termination			March 2012

On June 22, 2010, we, along with GMP, made a claim under the September 6, 2001 VY PPA. The claim is that Entergy-Vermont Yankee breached its obligations under the agreement by failing to detect and remedy the conditions that resulted in cooling tower-related failures at the Vermont Yankee nuclear plant in 2007 and 2008. Those failures caused us and GMP to incur substantial incremental replacement power costs.

We are seeking recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the VY 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 also reviewed the 2007 and 2008 root cause analysis reports by Entergy-Vermont Yankee and a December 22, 2008 reliability assessment provided by Nuclear Safety Associates to the State of Vermont. Entergy-Vermont Yankee disputes our claim. We cannot predict the outcome of this matter at this time.

The VY PPA 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 VY PPA following the uprate. Based on VYNPC's calculations the VYNPC Sponsors should be entitled to slightly more capacity and energy than they have been receiving under the VY PPA since the uprate. 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 the 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 forward market prices as of December 31, 2010, the incremental replacement cost of lost power is estimated to be $14.3 million over the remaining life of the contract. 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 recovery of increased costs 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.

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. The new Vermont Legislature elected on November 2, 2010 could vote differently, although the political makeup of the House and Senate remains largely unchanged. Also, Vermont elected a new governor who advocated as a member of the Vermont Senate and during the gubernatorial campaign that the Vermont Yankee plant should close when its current license expires. While circumstances could change and we expect to engage in a constructive dialogue with the new administration and legislature related to the continued operation of the Vermont Yankee plant, we are unable to predict the outcome at this time.

On March 10, 2011, the NRC voted 4-0 to approve the 20-year license extension through March 21, 2032 requested by Entergy-Vermont Yankee. This approval removes the last federal level regulatory requirement for relicensing of the Vermont Yankee station. However, the Vermont Legislature has not approved the license extension and such approval is considered unlikely at this time. Under Vermont law, in addition to a favorable Vermont legislative vote, the PSB needs to issue a Certificate of Public Good for the plant to continue to operate after March 21, 2012.

Entergy-Vermont Yankee is attempting to overcome legislative concerns, but has also recently intimated that it may challenge the state's authority as it relates to relicensing. In April 2010, we began a new round of negotiations on a new contract. While we rejected Entergy-Vermont Yankee's December 2009 public proposal of contract terms, we continue to exchange information and proposals with them. We cannot predict the outcome of this matter at this time.

Hydro-Québec: We are purchasing power from Hydro-Québec under the 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-Québec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO power contract runs through 2020, but our purchases under the contract end in 2016. The average level of deliveries under the current contract 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. The first 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 31, 2012.

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Québec. The first option was never exercised and expired December 31, 2010. The second gives Hydro-Québec 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 but due to the notice provision there is a maximum remaining application of three times available. To date, Hydro-Québec has not exercised this option. We have determined that this second option is not a derivative 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-Québec, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2010, our obligation is about 47 percent of the total VJO power contract through 2016, and represents approximately $285.7 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 contract in its 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 $335.1 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2011 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-Québec were $63 million in 2010, $63.1 million in 2009 and $63.7 million in 2008. Annual capacity costs decreased by $2.2 million starting November 1, 2009, and that cost reduction will continue for six contract years. A summary of the Hydro-Québec actual charges for 2010 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	
	2010	2011 - 2012	2013 -2016
Annual Capacity Acquired	**143.2 MW**	146.7 MW	(a)
Minimum Energy Purchase - annual load factor (b)	**75%**	75%	75%
Energy Charge	**$30,887**	$31,283	$19,631
Capacity Charge	**32,084**	32,543	19,874
Total Energy and Capacity Charge	**$62,971**	$63,826	$39,505
Average Cost per kWh	**$0.065**	$0.066	$0.068

(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 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 $22.9 million in 2010, $22.6 million in 2009 and $26.4 million in 2008. Estimated annual purchases are expected to range from $7.7 million to $22.6 million for the years 2011 through 2015. 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):

	2010			2009		
	Gross Investment	**Accumulated Depreciation**	**Net Investment**	Gross Investment	Accumulated Depreciation	Net Investment
Wyman #4	**$3,853**	**$3,121**	**$732**	$3,791	$3,018	$773
Joseph C. McNeil	**18,270**	**13,458**	**4,812**	18,221	12,874	5,347
Millstone Unit #3	**78,929**	**42,213**	**36,716**	78,638	41,229	37,409
Highgate Transmission Facility	**14,696**	**9,438**	**5,258**	14,747	9,090	5,657
	$115,748	**$68,230**	**$47,518**	$115,397	$66,211	$49,186

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 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 were 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. On April 12, 2010, the stay was lifted and a staggered briefing schedule was proposed, to which DNC has responded with a request to expedite the briefing schedule so that the appeals of all parties can be heard concurrently.

On June 30, 2010, the DOE filed its initial brief in the spent fuel damages litigation. This brief focuses on the costs awarded in connection with Millstone Unit #3. DNC replied to the government's brief in August, 2010. The government's reply brief was filed September 14, 2010 and briefing on the appeal is now complete. Oral argument on the government's appeal occurred before the Federal Circuit on January 12, 2011.

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. We expect that our share of a recovery, if any, would be credited to our retail customers.

Future Power Agreements *New Hydro-Québec Agreement:* On August 12, 2010 we, along with Green GMP, VPPSA, Vermont Electric Cooperative, Inc., Vermont Marble, Town of Stowe Electric Department, City of Burlington, Vermont Electric Department, Washington Electric Cooperative, Inc. and the 13 municipal members of VPPSA (collectively, the "Buyers") entered into an agreement for the purchase of shares of 218 MW to 225 MW of energy and environmental attributes from HQUS commencing on November 1, 2012 and continuing through 2038.

The rights and obligations of the Buyers under the HQUS PPA, including payment of the contract price and indemnification obligations, are several and not joint or joint and several. Therefore, we shall have no responsibility for the obligations, financial or otherwise, of any other party to the HQUS PPA. The parties have also entered into related agreements, including collateral agreements between each Buyer and HQUS, a Hydro-Québec guaranty, an allocation agreement among the Buyers, and an assignment and assumption agreement between us and Vermont Marble, related to the pending acquisition.

The HQUS PPA will replace approximately 65 percent of the existing VJO power contract discussed above, which along with the VY PPA supply the majority of Vermont's current power needs. The VJO power contract and the VY PPA expire within the next several years.

The obligations of HQUS and each Buyer are contingent upon the receipt of certain governmental approvals. On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. The PSB has established a schedule for the docket including technical hearings and final legal briefs in the first quarter of 2011. In the event the HQUS PPA is terminated with respect to any Buyer as a result of such Buyer's failure to receive governmental approvals, each of the other Buyers will have an option to purchase the additional energy.

Under the Agreement, subject to regulatory approval, we would be entitled to purchase an energy quantity of up to 85.4 MW from November 1, 2015 to October 31, 2016; 96.4 MW from November 1, 2016 to October 31, 2020; 98.4 MW from November 1, 2020 to October 31, 2030; 112.1 MW from November 1, 2030 to October 31, 2035; and 26.7 MW from November 1, 2035 to October 31, 2038.

Other Future Power Agreements: As we continue to build and diversify our power portfolio as planned and to comply with state law which establishes goals for including renewable power in our mix, we have recently signed several agreements for clean and competitively priced renewable energy. On September 9, 2010 we agreed to terms for purchasing output over nine years from Iberdrola Renewables' planned Deerfield Wind Project. The agreement was signed by the parties on December 13, 2010.

Other recently signed agreements include: two separate agreements to purchase 30.3 percent of the actual output from Granite Reliable Wind project for 20 years beginning April 1, 2012 and an additional 20 percent for 15 years beginning in November 2012; an agreement to purchase the entire 4.99 MW output of Ampersand Gilman Hydro for five years starting April 1, 2012; and 15 MW of around-the-clock energy from J.P. Morgan Ventures Energy for the calendar years 2013 through 2015.

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 Millstone Unit #3 decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements have been 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 Note 4 - 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 the other former owners and must be applied to the benefit of retail customers.

Nuclear Insurance The Price-Anderson 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 EPACT reinstated and extended the Price-Anderson Act for 20 years. There are two levels of coverage. The primary level provides liability insurance coverage of $375 million, or the maximum private insurance available. If this amount is not sufficient to cover claims arising from an accident, the second level applies offering additional coverage up to $12.6 billion per incident. For the second level, each operating nuclear plant must pay a retrospective premium equal to its proportionate share of the excess loss, up to a maximum of $111.9 million per reactor per incident, limited to a maximum annual payout of $17.5 million per reactor. These assessments will be adjusted for inflation and U.S. Congress can modify or increase the insurance liability coverage limits at any time through legislation. 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.

Performance Assurance We are subject to performance assurance requirements through ISO-NE under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $3.2 million with ISO-NE. 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, 2010, we had posted $6.6 million of collateral under performance assurance requirements for certain of our power contracts, $5.5 million of which was represented by a letter of credit and $1.1 million of which was represented by cash and cash equivalents. 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 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.

As of December 31, 2010, our Environmental Reserve was $0.8 million, compared to $1.6 million in 2009, and $1.7 million in 2008. A summary of the Environmental Reserve as of December 31, 2010 follows (dollars in thousands):

	2010	2009	2008
Environmental reserve balance at beginning of year	**$1,565**	$1,732	$1,918
Charged to income and expenses	**838**		
Deductions	**(1,567)**	(167)	(186)
Environmental reserve balance at end of year	**$836**	**$1,565**	**$1,732**

The reserve for environmental matters is 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 applicable reporting periods. 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, PCB contamination and the potential for off-site migration, we conducted studies in the late 1980s and early 1990s to quantify the nature and extent of contamination and potential costs to remediate the site. Investigation at the site continued, including work with the State of Vermont to develop a mutually acceptable solution. In June 2010, both the VANR and the Environmental Protection Agency approved separate remediation work plans for the manufactured gas plant and PCB waste at the site. Remedial work started in August 2010 and concluded in early December 2010. We discovered more PCB contamination than anticipated at this site and it was necessary to excavate and dispose of additional material. As a result, the reserve was increased by $0.6 million in 2010. Remediation is nearly complete as of December 31, 2010. Some additional sitework including grading and vegetation planting will occur in 2011. In February 2011, we submitted a Construction Completion Report for the project to the EPA and VANR for review. The report documented remedial construction and confirmatory sampling activities. As of December 31, 2010, our remaining obligation is less than $0.1 million.

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, although 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 probabilistic 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 of December 31, 2010, our remaining obligation is $0.5 million.

Currently, the Windham Regional Commission and the Town of Brattleboro are pursuing the redevelopment of the gas plant site and waterfront area into vehicle parking with green space. This concept calls for the removal of the remnant gas plant building plus covering and otherwise avoiding contaminated areas instead of removing contaminated soil and debris. We are assessing the cost implications of this conceptual plan. Currently we do not believe the impact of the plan will be material.

Dover, New Hampshire, Manufactured Gas Facility: In 1999, 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 we paid based on completion of PSNH's cleanup effort. As of December 31, 2010, our remaining obligation was less than $0.1 million.

Middlebury Lower Substation: By letter dated February 5, 2010, the VANR Sites Management Section informed us they require additional investigation of the soil contamination at the Middlebury Lower Substation. This was a result of voluntarily submitted information from an internal soil sampling that we completed in the fall of 2009. The soil sampling showed elevated levels of TPH, which will require remediation. Substation reconstruction started in October 2010 after a delay for an archeological investigation. The environmental site work consists of the removal and landfill disposal of the slightly contaminated soil. As of December 31, 2010, our remaining obligation was less than $0.1 million.

Salisbury Substation: We completed internal testing and found PCBs and TPH, as well as small quantities of pesticides in the soil and concrete at this site. The substation is located adjacent to the Salisbury hydroelectric power station. It is scheduled to be retired and replaced during 2011. Final results indicated that PCB, TPH, and pesticide concentrations exceed state and federal regulatory limits at portions at the site. We submitted a letter to the VANR Sites Management Section proposing that PCB remediation efforts would be sufficient mitigation for TPH and pesticide contamination, and proposed to collect soil samples for confirmatory testing of these compounds. A cost estimate was made, and we reserved $0.2 million for the cost of the cleanup at this site.

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.

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. Under the terms of the agreements with Catamount and Diamond Castle Holdings, 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. To management's knowledge, there is no pending or threatened litigation with the potential to cause material expense. No government agency has sought funds from us for any study or remediation.

Leases and support agreements *Capital Leases:* We had obligations under capital leases of $4.4 million at December 31, 2010 and $5.3 million at December 31, 2009. 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 $4.4 million, $4.2 million is related to the Hydro-Québec Phase II transmission facilities and the remaining $0.2 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 $33 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, 2010, the $4.2 million unamortized balance was comprised of $19.3 million related to our share of original costs and additional investments, offset by $15.1 million of accumulated amortization.

We also participated with other electric utilities in the construction of the Hydro-Québec 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, 2010, 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 million in 2011 to $2.5 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 ISO-NE Open Access Transmission Tariff.

For the year ended December 31, 2010, imputed interest on capital leases totaled $0.5 million. A summary of minimum lease payments as of December 31, 2010 follows (dollars in thousands).

Year	Capital Leases
2011	$1,282
2012	1,199
2013	1,111
2014	978
2015	757
Future minimum lease payments	5,327
Less: amount representing interest	(915)
Present value of net minimum lease payments	$4,412

Operating Leases: We have two master lease agreements for vehicles and related equipment. On October 30, 2009, we signed a vehicle lease agreement to finance many of the vehicles covered by a former agreement. 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, 2010 is approximately $0.4 million. The total future minimum lease payments required for all lease schedules under this agreement at December 31, 2010 is $3.7 million. The maximum amount approved for lease under this agreement is $5.5 million, of which $5.3 million was outstanding at December 31, 2010. At December 31, 2009, the maximum amount available for lease under this agreement was $5.5 million, of which $5.4 million was outstanding.

On October 24, 2008, we entered into an operating lease for new vehicles and other related equipment. 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, 2010 is $2.2 million. As of December 31, 2010 there is no credit line in place for additions under this agreement in 2011. The total acquisition cost of all lease additions under this agreement at December 31, 2010 was $2.9 million. At December 31, 2009 the total acquisition cost of all lease additions under this agreement was $2.6 million.

Other operating lease commitments are considered minimal, as most are cancelable after one year from inception or the future minimum lease payments are of a nominal amount.

At December 31, 2010, future minimum rental payments required under non-cancelable operating leases are expected to total $5.4 million, consisting of $1.8 million in 2011, $1.4 million in 2012, $1.2 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 $6.1 million in 2010, $6.3 million in 2009 and 2008. 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 purchased power expense on the Consolidated Statement of Income. The balance of the reserve was $6 million at December 31, 2010 and $7.2 million at December 31, 2009. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets.

Customer Bankruptcy On October 26, 2009, a large customer filed for bankruptcy protection. In December 2010, the PSB approved the final bankruptcy plan and in January 2011, the court approved the plan and final settlement. As of December 31, 2010, we reversed the reserve of $1.1 million that was previously recorded in 2009 and received payment in January 2011.

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, 2010 and 2009.

NOTE 20 – PENDING ACQUISITIONS

Vermont Marble Power Division: On April 30, 2010, we signed a purchase and sale agreement with Omya, Inc. to purchase certain generating, transmission and distribution assets of Vermont Marble located in the State of Vermont. Under this agreement, we will pay $33.2 million for the transmission and distribution assets and generating assets comprised of four hydroelectric generating stations. The agreement contains usual and customary purchase and sale terms and conditions and is contingent upon federal and state regulatory approvals.

With Omya, Inc., we filed a joint petition with the PSB on August 2, 2010, requesting that they consent to the proposed sale by Omya and purchase by us of assets used in the public service business of Vermont Marble and approve certain related matters. As part of the proposed purchase and sale, we will acquire from Vermont Marble, among other things, four hydroelectric facilities on Otter Creek and Vermont Marble's transmission and distribution facilities, which include approximately 56 miles of 46 kV transmission lines, 11 miles of 2.4/4.16 kV distribution lines, one distribution substation in the Village of Proctor, and two transmission substations. On September 14, 2010, the PSB held a prehearing conference and subsequently established a schedule for resolution of the docket including technical hearings and the filing of final legal briefs.

On October 28, 2010, we received approval from FERC, subject to certain conditions, for the proposed transaction.

On February 25, 2011, we filed an MOU between us, the DPS, the Town of Proctor and Omya, with the PSB that resolves all the outstanding issues between the parties concerning our acquisition of Vermont Marble. As part of the settlement, we will pay $28.3 million for the generating assets and approximately $1 million for the transmission and distribution assets. We will be allowed recovery from customers of $27 million for the generating assets and the $1 million for the transmission and distribution assets.

The agreement includes a five-year, six-step phase-in of residential rate changes for existing Vermont Marble customers, which will be funded by Omya up to an amount estimated to be approximately $1.1 million. The agreement also requires creation of a value sharing pool that provides for certain excess value received by us to be split between our customers, Omya and our shareholders if energy market prices and hydro improvements create more value than anticipated.

On March 4, 2011 we signed an amended and restated purchase and sale agreement with Omya, Inc. to incorporate the terms of the MOU filed on February 25, 2011.

Readsboro Electric Department: On October 27, 2010, we signed a purchase and sale agreement with Readsboro. The $0.4 million purchase price includes all of the assets of Readsboro including about 14 miles of distribution line and associated equipment, and the exclusive franchise Readsboro holds to serve its 319 customers. The sale is contingent upon approval by the PSB. On February 24, 2011 we, along with the DPS and Readsboro, filed a petition with the PSB that resolves the issues outstanding in our acquisition of Readsboro. The PSB is expected to rule on the petition for approval of the transaction in the first half of 2011.

NOTE 21- 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. East Barnet is included with CV- VT in the table below. **Other Companies** represents our non-utility operations and consists of CRC, and C.V. Realty, Inc. CRC was formed to hold our subsidiaries that invest in unregulated business opportunities and is the parent company of SmartEnergy Water Heating Services, Inc., which engages in the sale and rental of electric water heaters in Vermont and New Hampshire. C.V. Realty, Inc. is a real estate company whose purpose is to own, acquire, buy, sell and lease real and personal property and interests.

The accounting policies of operating segments are the same as those described in Note 2 - 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 were a nominal amount in all periods presented. The following table provides segment financial data for the period ended December 31 (dollars in thousands):

2010	CV VT	Other Companies	Reclassification and Consolidating Entries	Consolidated
Revenues from external customers	**$341,925**	**$1,731**	**($1,731)**	**$341,925**
Depreciation and amortization (a)	**$15,038**	**$189**	**($189)**	**$15,038**
Operating income tax expense	**$7,545**	**$278**	**($278)**	**$7,545**
Equity in earnings of affiliates	**$21,098**	**$0**	**$0**	**$21,098**
Interest income (b)	**$183**	**$2**	**$0**	**$185**
Interest expense	**$11,560**	**$0**	**$0**	**$11,560**
Net income	**$20,526**	**$428**	**$0**	**$20,954**
Investments in affiliates	**$171,514**	**$0**	**$0**	**$171,514**
Total assets	**$707,973**	**$3,019**	**($246)**	**$710,746**
Construction and plant expenditures (c)	**$33,021**	**$290**	**$0**	**$33,311**
2009				
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 (d)	$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	$36,835	$339	$0	$37,174

(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 22 - 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)
2010					
Operating revenues	**$91,007**	**$79,937**	**$85,392**	**$85,589**	**$341,925**
Utility operating income	**$3,255**	**$1,103**	**$8,629**	**$4,468**	**$17,455**
Net income	**$4,202**	**$1,445**	**$9,990**	**$5,317**	**$20,954**
Basic earnings per share	**$0.35**	**$0.11**	**$0.79**	**$0.40**	**$1.66**
Diluted earnings per share	**$0.35**	**$0.11**	**$0.79**	**$0.40**	**$1.66**
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

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

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Management of the company, under the supervision and with participation of our Chief Executive Officer and Principal Financial and Accounting Officer, conducted an evaluation of the effectiveness of the design and operation of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")), as of December 31, 2010. Based on this evaluation, our Chief Executive Officer and Principal Financial and Accounting Officer concluded that, as of December 31, 2010, the company's disclosure controls and procedures are effective at the reasonable assurance level.

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, 2010.

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 were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2010 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, 2010, 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, 2010, 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 as of and for the year ended December 31, 2010 of the Company and our report dated March 14, 2011, which report expressed an unqualified opinion on those consolidated financial statements and refers to the reports of other auditors (which as to Vermont Electric Power Company, Inc. included an explanatory paragraph concerning a change in accounting for non-controlling interests).

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 14, 2011

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

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated herein by reference to the section entitled "Director Elections" of the Proxy Statement of the Company for the 2011 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 24, 2011.

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 2011 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 24, 2011.

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 2011 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 24, 2011. 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	137,330	$17.89	-
Omnibus Stock Plan	104,369	$20.20	116,770
Total	**284,997**	**$19.129**	**116,770**

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 2011 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 24, 2011.

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 2011 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 24, 2011.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

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

Consolidated Statements of Income for the three years ended December 31, 2010, 2009 and 2008

Consolidated Statements of Comprehensive Income for the three years ended December 31, 2010, 2009 and 2008

Consolidated Statements of Cash Flows for the three years ended December 31, 2010, 2009 and 2008

Consolidated Balance Sheets at December 31, 2010 and 2009

Consolidated Statements of Changes in Common Stock Equity at December 31, 2010, 2009 and 2008

Notes to Consolidated Financial Statements

(a)2. Required information related to Schedule II - Reserves for the three years ended December 31, 2010, 2009 and 2008 is included herein under Part II, Item 8, Financial Statements and Supplementary Data, Notes to Consolidated Financial Statements

(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 November 7, 2010. (Exhibit 99.2, Current Report on Form 8-K Filed November 10, 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)

4-9 Bond Purchase Agreement, dated as of November 18, 2010, among the Company, Vermont Economic Development Authority, and KeyBanc Capital Markets, Inc. (Exhibit 4-9, Current Report on Form 8-K Filed November 19, 2010, File No. 1-8222)

4-10 Forty-Seventh Supplemental Indenture, dated as of December 1, 2010, from the Company to U.S. Bank National Association, as trustee. (Exhibit 4-10, Current Report on Form 8-K Filed December 2, 2010, File No. 1-8222)

4-11 Loan and Trust Agreement, dated as of December 1, 2010, among the State of Vermont, acting by and through the Vermont Economic Development Authority, the Company and U.S. Bank National Association, as trustee. (Exhibit 4-11, Current Report on Form 8-K Filed December 2, 2010, File No. 1-8222)

4-12 Bond Purchase Agreement, dated as of February 4, 2011, among the Company and Metropolitan Life Insurance Company and its affiliates. (Exhibit 4-12, Current Report on Form 8-K Filed February 4, 2011, File No. 1-8222)

Exhibit 10 Material Contracts (* Denotes filed herewith)

Incorporated herein by reference:

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

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

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

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

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

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

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

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

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

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

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

10.4.1 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)

10-64 Power Purchase and Sale Agreement between H. Q. Energy Services (U.S.), Inc. and Central Vermont Public Service Corporation, Green Mountain Power, Vermont Electric Cooperative, Inc., Vermont Public Power Supply Authority, Vermont Marble Power Division of Omya, Inc., City of Burlington, Vermont Electric Department, and The Town of Stowe Electric Department dated as of August 12,2010 [portions of the exhibit were omitted pursuant to a request for confidential treatment on file with the SEC] (Exhibit 10.1, Current Report on Form 8-K filed August 18, 2010, File No. 1-8222)

10-65 Agreement between Central Vermont Public Service Corporation, The Article 6 Marital Trust, Anita G. Zucker Trustee, and Robert B. Johnston, dated November 7, 2010, regarding nomination/appointment of Mr. Johnston to the Company's Board of Directors. (Exhibit 10-64, Current Report on Form 8-K filed November 10, 2010, File No. 1-8222)

10-66 Memorandum of Understanding, dated December 20, 2010, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10-65, Current Report on Form 8-K filed December 22, 2010, 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	Form of Change in Control Agreement effective March 1, 2011.
A 10.7	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 10.8	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 10.9	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 10.10	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	Performance Share Incentive Plan, Effective January 1, 2011
A 10.13	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 10.14	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 10.15	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 10.16	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 10.17	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 10.18	Management Incentive Plan, Effective January 1, 2011.

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.

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, 2011

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, 2011.

Signature	Title
Robert H. Young*	Executive Chairman (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
Robert B. Johnston*	Director
Elisabeth B. Robert*	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.