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

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

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

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

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

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

Transmission services provided by Transco are billed to us under the VTA. All Vermont electric utilities are parties to the VTA. This agreement requires the Vermont utilities to pay their pro rata share of Transco's total costs, including interest and a fixed rate of return on equity, less the revenue collected under the ISO-New England Open Access Transmission Tariff and other agreements. In June 2007, FERC issued an order combining three FERC filings related to the VTA, including a request by five municipal utilities for FERC approval to withdraw from the VTA and take transmission service under a different tariff, and requests by Transco for revisions to the VTA. The parties reached a preliminary settlement in January 2008 and filed a definitive settlement agreement with the FERC in March 2008. The settlement agreement is supported by all parties, including us, and resolves all issues that were raised in the FERC proceedings. The FERC approved the settlement agreement on August 22, 2008, and related amendments to the Transco operating agreement necessary to implement the settlement were approved by the PSB.

Transco's billings to us primarily include the VTA and charges and reimbursements under the NEPOOL Open Access Transmission Tariff ("NOATT"). Transco's billings to us of $8 million in 2009, $7.3 million in 2008 and $5.1 million in 2007 are included in Transmission - affiliates on our Consolidated Statements of Income. Accounts payable to Transco were $0.8 million at December 31, 2009 and $0.4 million at December 31, 2008. Cash dividends received were $9 million in 2009, $9.1 million in 2008 and $3.1 million in 2007.

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

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

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

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

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

VYNPC's revenues shown in the table above include sales to us of $64 million in 2009, $57.7 million in 2008 and $55.8 million in 2007. These amounts are included in Purchased power - affiliates on our Consolidated Statements of Income. Also included in VYNPC's revenues above are sales of $0.3 million each year representing a small portion of our entitlement received by a secondary purchaser. Accounts payable to VYNPC were $5.6 million at December 31, 2009 and $5.3 million at December 31, 2008. Cash dividends received were $0.3 million in 2009, 0.2 million in 2008 and $0.4 million in 2007.

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

	Remaining Obligations	Revenue Requirements	Company Share
Maine Yankee	$ 119.9	$ 47.9	$ 1.0
Connecticut Yankee	$ 146.4	$ 274.1	$ 5.5
Yankee Atomic	$ 101.7	$ 58.8	$ 2.1

The remaining obligations are the estimated remaining total costs to be incurred by the respective Yankee companies to operate the supporting organization and decommission the plant, including onsite spent fuel storage, in 2009 dollars for the period 2010 through 2023 for Maine Yankee and Connecticut Yankee and through 2022 for Yankee Atomic. Revenue requirements are the estimated future payments by the sponsors to fund estimated FERC-approved decommissioning and other costs (in nominal dollars) for 2010 through 2013 for Maine Yankee, 2015 for Connecticut Yankee and 2014 for Yankee Atomic. Revenue requirements include Maine Yankee and Connecticut Yankee collections for required contributions to pre-1983 spent fuel funds. Yankee Atomic has already collected and paid these required pre-1983 contributions. These estimates may be revised from time to time based on information available to the company regarding estimated future costs. Our share of the estimated costs shown in the table above is included in regulatory assets and nuclear decommissioning liabilities (current and non-current) on the Consolidated Balance Sheets.

Maine Yankee: Maine Yankee's wholesale rates are currently based on a 2008 FERC-approved settlement. Our share of decommissioning and other costs amounted to $0.1 million in 2009, $0.9 million in 2008 and $1.1 million in 2007. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income.

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

Connecticut Yankee: Connecticut Yankee's wholesale rates are currently based on a 2006 FERC-approved settlement. Our share of decommissioning and other costs amounted to $0.8 million in both 2009 and 2008 and $1 million in 2007. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income. Our share of dividends from Connecticut Yankee was $0.1 million in 2009. There were no dividends received in 2008. Our share of proceeds from Connecticut Yankee stock redemption in 2009 was $0.1 million. There were no proceeds from stock redemptions on 2008.

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

Yankee Atomic: Yankee Atomic's wholesale rates are currently based on a 2006 FERC-approved settlement. Based on the approved settlement, Yankee Atomic agreed to reduce its revenue requirements by $79 million for the period 2006-2010 and to increase its revenue requirements by $47 million for the period 2011-2014. The revision includes adjustments for contingencies, projected escalation and certain decontamination and dismantling expenses. The approved settlement also provides for reconciling and adjusting future charges based on actual decontamination and dismantling expenses and the decommissioning trust fund's actual investment earnings. Our share of decommissioning and other costs amounted to $0.4 million in 2009, 2008 and 2007. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income.

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

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

In 2006, the United States Court of Federal Claims issued judgment in the spent fuel litigation. Maine Yankee was awarded $75.8 million in damages through 2002, Connecticut Yankee was awarded $34.2 million through 2001 and Yankee Atomic was awarded $32.9 million through 2001. In December 2006, the DOE filed a notice of appeal of the court's decision and all three companies filed notices of cross appeals. In August 2008, the United States Court of Appeals for the Federal Circuit reversed the award of damages and remanded the cases back to the trial court. The remand directed the trial court to apply the acceptance rate in 1987 annual capacity reports when determining damages.

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

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

The Court of Federal Claims' original decision, if maintained on remand, established the DOE's responsibility for reimbursing Maine Yankee for its actual costs through 2002 and Connecticut Yankee and Yankee Atomic for their actual costs through 2001 related to the incremental spent fuel storage, security, construction and other costs of the spent fuel storage installation. Although the decision did not resolve the question regarding damages in subsequent years, the decision did support future claims for the remaining spent fuel storage installation construction costs.

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

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

NOTE 4 - FINANCIAL INSTRUMENTS

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

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

The estimated fair values of power contract derivatives are based on over-the-counter quotes or broker quotes at the end of the reporting period, with the exception of one long-term power contract that is valued using a binomial tree model and quoted market data when available, along with appropriate valuation methodologies. In 2009, the fair values were unrealized losses of $0.4 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $0.6 million that were recorded as assets on the Consolidated Balance Sheet. In 2008, the fair values were unrealized losses of $4.1 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $12.9 million that were recorded as assets on the Consolidated Balance Sheet.

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

The table above does not include cash, special deposits, receivables and payables. The carrying values approximate fair value because of the short duration of those instruments. Also, the carrying values of our Vermont Industrial Development Authority Bonds ("VIDA") and Connecticut Development Authority Bonds ("CDA") approximate fair value since the rates are adjusted at least monthly. The carrying value of our credit facilities approximates fair value since the rates can change daily. The fair value of our cash equivalents and restricted cash are included in Part II, Item 8, Note 5 - Fair Value.

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

Our accounts receivable are not collateralized. As of December 31, 2009, approximately 5 percent of total accounts receivable are with wholesale entities engaged in the energy industry. This industry concentration could affect our overall exposure to credit risk, positively or negatively, since customers may be similarly affected by changes in economic, industry or other conditions.

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

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

NOTE 5 - FAIR VALUE

Effective January 1, 2008, we adopted FASB's guidance for fair value measurements, as required. The guidance establishes a single, authoritative definition of fair value, prescribes methods for measuring fair value, establishes a fair value hierarchy based on the inputs used to measure fair value and expands disclosures about the use of fair value measurements; however, the guidance does not expand the use of fair value accounting in any new circumstances. The guidance defines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date."

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NOTE 6 - INVESTMENT SECURITIES

Millstone Decommissioning Trust Fund We have decommissioning trust fund investments related to our joint-ownership interest in Millstone Unit #3. The decommissioning trust fund was established pursuant to various federal and state guidelines. Among other requirements, the fund must be managed by an independent and prudent fund manager. Any gains or losses, realized and unrealized, are expected to be refunded to or collected from ratepayers and are recorded as regulatory assets or liabilities in accordance with the FASB guidance for Regulated Operations.

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

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

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

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

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

Information related to the fair value of debt securities at December 31, 2009 follows (dollars in thousands):

	Fair value of debt securities at contractual maturity dates				
	Less than 1 year	**1 to 5 years**	**5 to 10 years**	**After 10 years**	**Total**
Debt Securities	$ 33	$ 267	$ 258	$ 677	$ 1,235

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

NOTE 7 - RETAIL RATES AND REGULATORY ACCOUNTING

Retail Rates Our retail rates are approved by the PSB after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The regulatory assets included in the table above are being recovered in retail rates and are supported by written rate orders. The recovery period for regulatory assets varies based on the nature of the costs. All regulatory assets are earning a return, except for income taxes, nuclear plant dismantling costs, and pension and postretirement medical costs. Other deferred charges – regulatory are supported by PSB-approved accounting orders or approved cost recovery methodologies, allowing cost deferral until recovery in a future rate proceeding. Most items listed in other deferred credits - regulatory are being amortized for periods ranging from two to three years. Pursuant to PSB-approved rate orders, when a regulatory asset or liability is fully amortized, the corresponding rate revenue shall be booked as a reverse amortization in an opposing regulatory liability or asset account.

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

NOTE 8 - SHARE-BASED COMPENSATION

We have awarded share-based compensation to key employees and non-employee directors under several stock compensation plans. Awards under these plans have been comprised of stock options, common stock and performance shares. The last stock option awards were made in 2005 and we do not anticipate making additional awards. At December 31, 2009 these plans included:

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

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

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

Total share-based compensation expense recognized in the income statement was $0.9 million in 2009, $0.8 million in 2008 and $0.6 million in 2007. The total income tax benefit recognized in the income statement for share-based compensation was $0.4 million in 2009, $0.3 million in 2008 and $0.2 million in 2007. No compensation costs were capitalized. Cash received from exercise of stock options was $0.4 million in 2009, $1 million in 2008 and $1.1 million in 2007. The tax benefit realized for the tax deductions from option exercises and performance shares issued was $0.3 million in 2009 and $0.4 million in 2008. The tax benefit realized for the tax deductions from option exercises was $0.4 million in 2007. These amounts are included in other paid in capital on the balance sheet.

Currently, stock options that are exercised and other stock awards are settled from original issue common shares. Under the existing plans, they may also be settled by the issuance of treasury shares or through open market purchases of common shares. Awards other than stock options can also be settled in cash at the discretion of the Compensation Committee of our Board of Directors. Historically, these awards have not been settled in cash.

Stock Options All outstanding stock options were granted at the fair market value of the common shares on the date of grant, and vested immediately. The maximum term of options is five years for non-employee directors and 10 years for key employees. Stock option activity during 2009 follows:

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

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

Common and Nonvested Shares The fair value of common stock granted to key employees and non-employee directors is equal to the market value of the underlying common stock on the date of grant. The shares vest immediately or cliff vest over predefined service periods. Although full ownership of the shares does not transfer to the recipients until vested, the recipients have the right to vote the shares and to receive dividends from the date of grant. A summary of common and nonvested share activity during 2009 follows:

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

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

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

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

The fair value of performance shares for operational measures was estimated based on the market value of the shares on the grant date and the expected outcome of each measure. The grant-date fair value of performance shares with operational measures granted in 2009 was $16.61 per share. Compensation cost is recognized over the three-year performance cycle and is adjusted for the actual percentage of target achieved.

The fair value of performance shares for TSR measures was estimated on the grant date using a Monte Carlo simulation model. The grant-date fair value of performance shares with TSR measures granted in 2009 was $21.59 per share. Compensation cost is recognized on a straight-line basis over the three-year performance cycle and is not adjusted for the actual percentage of target achieved. The weighted-average assumptions used in the Monte Carlo valuation for TSR performance shares granted during the past three years are shown in the table below.

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

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

A summary of performance share activity, excluding estimated dividend equivalents, during 2009 follows:

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

(a) Based on 100 percent performance level.

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

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

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

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

NOTE 9 - COMMON STOCK

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

NOTE 10 - TREASURY STOCK

Treasury stock is recorded at the average cost of $22.75 per share, including additional costs, and results in a reduction of shareholders' equity on the Consolidated Balance Sheet. In April 2006, we purchased 2,249,975 shares of our common stock at $22.50 per share using proceeds from the December 20, 2005 sale of Catamount. In July 2007, we began using Treasury shares to meet reinvestment needs under the Dividend Reinvestment Plan. In September 2009, we ceased using Treasury shares and began using original issue shares to meet reinvestment obligations under the Dividend Reinvestment Plan.

NOTE 11 - PREFERRED AND PREFERENCE STOCK NOT SUBJECT TO MANDATORY REDEMPTION

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

	2009	2008
Preferred stock, $100 par value, outstanding:		
4.150% Series; 37,856 shares	**$ 3,786**	$ 3,786
4.650% Series; 10,000 shares	**1,000**	1,000
4.750% Series; 17,682 shares	**1,768**	1,768
5.375% Series; 15,000 shares	**1,500**	1,500
Total preferred and preference stock not subject to mandatory redemption	**$ 8,054**	$ 8,054

There are 500,000 shares authorized of the Preferred Stock, $100 Par Value class that can be issued with or without mandatory redemption requirements. At December 31, 2009, a total of 90,538 shares were outstanding, including 80,538 that are not subject to mandatory redemption and are listed in the table above, and 10,000 that are subject to mandatory redemption and described in Part II, Item 8, Note 12 - Preferred Stock Subject to Mandatory Redemption. None of the outstanding Preferred Stock, $100 Par Value, is convertible into shares of any other class or series of our capital stock or any other security.

There are 1,000,000 shares authorized of Preferred Stock, $25 Par Value, and 1,000,000 shares authorized of Preference Stock, $1 Par Value. None of the shares are subject to mandatory redemption. There were none outstanding, issued or redeemed in 2009, 2008 or 2007.

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

All series of Preferred Stock are currently subject to redemption and retirement at our option upon vote of at least three-quarters of our Board of Directors in accordance with the specific terms for each series and upon payment of the Par Value, accrued dividends and a premium to which each would be entitled in the event of voluntary liquidation, dissolution or winding up of our affairs. At December 31, 2009, premiums payable on each series of non-redeemable preferred stock if such an event were to occur are as follows:

Preferred and Preference Stock	Premiums Per Share	
4.150% Series	$	5.50
4.650% Series	$	5.00
4.750% Series	$	1.00
5.375% Series	$	5.00

NOTE 12 - PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION

We have one series of Preferred Stock, $100 Par Value that is subject to mandatory redemption, 8.3 Percent Series Preferred Stock, with shares outstanding of 10,000 at December 31, 2009, 20,000 at December 31, 2008 and 30,000 at December 31, 2007. All of the provisions described in Part II, Item 8, Note 11 - Preferred and Preference Stock Not Subject to Mandatory Redemption are the same for the 8.3 Percent Series Preferred Stock, except that at December 31, 2009, the premium payable in the event of voluntary liquidation, dissolution or winding up of our affairs was at $1.245 per share. There are no dividends in arrears for the 8.3 Percent Series Preferred Stock.

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

Dividends paid on preferred stock subject to mandatory redemption are included in Other interest on the Consolidated Statements of Income, and amounted to $0.1 million in 2009, $0.2 million in 2008 and 2007.

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

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

	December 31, 2009	December 31, 2008
First Mortgage Bonds		
5.00%, Series SS, due 2011	**20,000**	20,000
5.72%, Series TT, due 2019	**55,000**	55,000
6.90%, Series OO, due 2023	**17,500**	17,500
6.83%, Series UU, due 2028	**60,000**	60,000
8.91%, Series JJ, due 2031	**15,000**	15,000
Revenue Bonds		
New Hampshire Industrial Development Authority Bonds ("NHIDA")		
3.75%, due 2009	**0**	5,450
Vermont Industrial Development Authority Bonds ("VIDA")*		
Variable, due 2013 (0.75% at December 31, 2009 and 0.85% at December 31, 2008)	**5,800**	5,800
Connecticut Development Authority Bonds ("CDA")*		
Variable, due 2015 (0.75% at December 31, 2009 and 1% at December 31, 2008)	**5,000**	5,000
Credit Facility		
$40 million unsecured revolving credit facility (0.8875 % at December 31, 2009)	**23,311**	0
Total long-term debt, notes payable and credit facility	**201,611**	183,750
Less current amount payable, due within one year	**0**	(16,250)
Total long-term debt, notes payable and credit facility, less current portion	**$ 201,611**	$ 167,500

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

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

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

Our debt financing documents do not contain cross-default provisions to affiliates outside of the consolidated entity. Certain of our debt financing documents contain cross-default provisions to our wholly owned subsidiaries, East Barnet, C.V. Realty, Inc. and Custom Investment Corporation. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions or the levy of significant judgments or attachments against our property. Currently, we are not in default under any of our debt financing documents. Scheduled sinking fund payments and maturities for the next five years are $0 in 2010, $20 million in 2011, $0 in 2012, $0 in 2013 and $0 in 2014.

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

The CDA and VIDA revenue bonds are floating rate, monthly demand pollution-control bonds. There are no interim sinking fund payments due prior to their maturity. The interest rates reset monthly. Both series are callable at par as follows: 1) at our option or the bondholders' option on each monthly interest payment date; or 2) at the option of the bondholders on any business day. There is a remarketing feature if the bonds are put for redemption. Historically, these bonds have been remarketed in the secondary bond market. Because of the three-year term of the new letters of credit discussed below, these revenue bonds were reclassified from Notes Payable to Long-Term Debt as of September 30, 2009.

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

Covenants: Our long-term debt indentures, letters of credit, credit facilities and material agreements contain financial covenants. The most restrictive financial covenants include maximum debt to total capitalization of 65 percent, and minimum interest coverage of 2.0 times. At December 31, 2009, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit, credit facilities and material agreements. A significant reduction in future earnings or a significant reduction to common equity could restrict the payment of common and preferred dividends or could cause us to violate our maintenance covenants. If we were to default on our covenant, the lenders could take such actions as terminate their obligations, declare all amounts outstanding or due immediately payable, or take possession of or foreclose on mortgaged property.

Credit Facility: We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated November 3, 2008. It contains financial and non-financial covenants. Our obligation under the Credit Agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. Financing terms and costs include an annual commitment fee of 0.15 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.7 percent on the average daily amount of letters of credit outstanding, all based on our unsecured issuer rating. Terms also include the requirement to collateralize any outstanding letters of credit in the event of a default under the credit facility. The facility contains a Material Adverse Effect (“MAE”) clause (a standard that requires greater adversity than a Material Adverse Change clause). The MAE clause could allow the lending institution to deny a transaction under the credit facility at the point of request. The credit facility also contains cross-default provisions to any of our subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or voluntary or involuntary liquidation, reorganization or bankruptcy. At December 31, 2009 $23.3 million in loans and no letters of credit were outstanding under this credit facility.

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

Dividend and Optional Stock Redemption Restrictions: Our revolving credit facilities described above restricts optional redemptions of capital stock and other restricted payments as defined. The First Mortgage Bond indenture and our Articles of Association also contain certain restrictions on the payment of cash dividends on and optional redemptions of all capital stock. Under the most restrictive of these provisions, $75.7 million of retained earnings was not subject to such restriction at December 31, 2009. The Articles also restrict the payment of common dividends or purchase of any common shares if the common equity level falls below 25 percent of total capital, applicable only as long as Preferred Stock is outstanding. Our Articles of Association also contain a covenant that requires us to maintain a minimum common equity level of about $3.3 million as long as any Preferred Stock is outstanding.

NOTE 14 - POWER-RELATED DERIVATIVES

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

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

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

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

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

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

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

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

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

NOTE 15 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

We have a qualified, non-contributory, defined-benefit pension plan ("Pension Plan") covering unionized and non-unionized employees subject to certain eligibility criteria. Under the terms of the Pension Plan, employees are vested after completing five years of service, and can receive a pension benefit when they are at least age 55 with a minimum of 10 years of service. They are eligible to choose between various payment options such as a monthly benefit or a one-time lump-sum amount depending on factors such as years of service earned at the date of retirement. Our funding policy is to contribute to the pension trust fund the greater of the annual actuarial cost or the statutory minimum. We are not required by our union contract to contribute to multi-employer plans. At the end of 2008, we adopted the Fully Generational mortality table. This replaces the RP-2000 mortality table.

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

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

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

FASB's guidance for employee retirement benefits requires an employer with a defined benefit plan or other postretirement plan to recognize an asset or liability on its balance sheet for the overfunded or underfunded status of the plan. For pension plans, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For postretirement benefit plans, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation.

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

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

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

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

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at the December 31 measurement date for 2009 and 2008 are shown in the table that follows. The selection methodology used in determining discount rates includes portfolios of “Aa” bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million in par value. The following weighted-average assumptions for pension and postretirement medical benefits were used in determining our related liabilities at December 31:

	Pension Benefits		Postretirement Medical Benefits	
	2009	2008	**2009**	2008
Discount rates	**6.00%**	6.15%	**5.50%**	6.05%
Rate of increase in future compensation levels	**4.25%**	4.25%	**4.25%**	4.25%

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

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

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

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

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

Investment Strategy Our pension investment policy seeks to achieve sufficient growth to enable the Pension Plan to meet our future benefit obligations to participants, to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 61 percent of plan assets be invested in equity securities and 39 percent of plan assets be invested in debt securities. The debt securities are comprised of long-duration bonds to match changes in plan liabilities. In response to market conditions, our pension trust committee voted to temporarily revise our target allocation in mid-December 2008, but we returned to the target asset allocation shown above in mid-2009.

Our postretirement medical benefit plan investment policy seeks to achieve sufficient funding levels to meet future benefit obligations to participants and minimize near-term cost volatility. Current guidelines specify generally that 60 percent of the plan assets be invested in equity securities and 40 percent be invested in debt securities. Fixed-income securities are of a shorter duration to better match the cash flows of the postretirement medical obligation.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Amounts recognized in Regulatory Assets and Accumulated Other Comprehensive Loss ("AOCL") The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2009 consisted of (dollars in thousands):

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

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

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

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

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

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

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

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

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

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

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

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

In formulating the assumed rate of return, we considered historical returns by asset category and expectations for future returns by asset category based, in part, on simulated capital market performance over the next 10 years.

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

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

Expected Cash Flows The table below reflects the total benefits expected to be paid from the external Pension Plan trust fund or from our assets, including both our share of the pension and postretirement benefit costs and the share of the postretirement medical benefit cost funded by participant contributions. Expected contributions reflect amounts expected to be contributed to funded plans. Of the benefits expected to be paid in 2010, approximately $8.2 million will be paid from the Pension Plan trust fund, and $2.3 million will be paid from the postretirement medical trust funds to reimburse us for out-of-pocket benefit payments. Information about the expected cash flows for the Pension Plan and postretirement medical benefit plans is as follows (dollars in thousands):

	Pension Benefits	Postretirement Medical Benefits	
		Gross	Expected Federal Subsidy
Employer Contributions			
2010	$ 3,300	$ 3,000	
Expected Benefit Payments			
2010	$ 8,183	$ 2,317	$ 230
2011	7,685	2,420	248
2012	10,886	2,509	267
2013	8,058	2,642	286
2014	9,697	2,750	305
2015 - 2019	48,772	13,763	1,916

As of December 31, 2009, the Medicare Part D subsidy reduced the postretirement benefit obligation by $5.4 million and reduced the 2009 net periodic benefit cost by $1.7 million. The estimated Medicare Part D subsidy included in the expected gross postretirement medical benefit payments is shown above.

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Long-term Disability We record non-accumulating post-employment long-term disability benefits in accordance with FASB's guidance for Contingencies. For 2009, the year-end post-employment medical benefit obligation was $1.2 million, of which $1.1 million was recorded as Accrued pension and medical benefit obligations and $0.1 million was recorded as Other current liabilities. The 2008 year-end post-employment medical benefit obligation was $1.6 million, of which $1.5 million was recorded as Accrued pension and medical benefit obligations and $0.1 million was recorded as Other current liabilities. The pre-tax post-employment benefit costs charged to expense (credit), including insurance premiums, were $(0.1) million in 2009, $0.1 million in 2008 and $0.2 million in 2007.

401(k) Savings Plan Most eligible employees choose to participate in our 401(k) Savings Plan. This savings plan provides for employee pre-tax and post-tax contributions up to specified limits. We match employee pre-tax contributions after one year of service. On January 1, 2007, the match increased from a maximum of 4.0 percent to a maximum of 4.25 percent of eligible compensation. Eligible employees are at all times vested 100 percent in their pre-tax and post-tax contribution account and in their matching employer contribution. Our matching contributions amounted to $1.5 million in 2009, $1.4 million in 2008 and $1.3 million in 2007.

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

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

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

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

NOTE 16 - INCOME TAXES

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

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

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

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

We follow FASB's guidance and methodology for estimating and reporting amounts associated with uncertain tax positions and we adopted the related guidance on January 1, 2007, as required. Upon adoption, we recognized the cumulative effect of approximately $0.1 million as an increase in the beginning balance of retained earnings related to a decrease in the liability for unrecognized tax benefits.

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

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

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

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

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

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

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

NOTE 17 - COMMITMENTS AND CONTINGENCIES

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

Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. A scheduled refueling outage was completed in November 2008 and the next outage is scheduled for the spring of 2010. Our total VYNPC purchases were $64 million in 2009, $57.7 million in 2008 and $55.8 million in 2007.

Prices under the PPA increase $1 per megawatt-hour each calendar year, from $43 in 2010 to $45 in 2012. The PPA contains a provision known as the "low market adjuster", which calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. Estimated annual purchases are expected to be $61 million for 2010, $63 million for 2011 and $16 million for 2012 when the contract expires in March. A summary of the PPA, including the actual amount for 2009 and the estimated average amounts through 2012, is shown in the table below. The total cost estimates are based on projected mWh purchase volumes at PPA rates, plus estimates of VYNPC costs, primarily net interest expense and the cost of capital. Actual amounts may differ.

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

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

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

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

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

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

The PPA between Entergy-Vermont Yankee and VYNPC contains a formula for determining the VYNPC power entitlement following an uprate in 2006 that increased the plant's operating capacity by approximately 20 percent. VYNPC and Entergy-Vermont Yankee are seeking to resolve certain differences in the interpretation of the formula. At issue is how much capacity and energy VYNPC Sponsors receive under the PPA following the uprate. Based on VYNPC's calculations the VYNPC Sponsors should be entitled to slightly more capacity and energy than they are currently receiving under the PPA. We cannot predict the outcome of this matter at this time.

Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that we could lose this resource if the plant shuts down for any reason before that date. An early shutdown could cause our customers to lose economic benefit of an energy volume of close to 50 percent of our total committed supply and we would have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on now available forward market prices as of December 31, 2009, the incremental replacement cost of lost power is estimated to average $27.5 million in 2010. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results if the costs are recovered in retail rates in a timely fashion.

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

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

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

Hydro-Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO Power Contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between us and Hydro-Quebec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO contract runs through 2020, but our purchases under the contract end in 2016. The average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015.

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

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

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Quebec. The first option gives Hydro-Quebec the right, upon four years' written notice, to reduce capacity and associated energy deliveries by 50 MW, including the use of a like amount of our Phase I/II transmission facility rights. The second gives Hydro-Quebec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Quebec. This second option can be exercised five times through October 2015. To date, Hydro-Quebec has not exercised these options. We have determined that the first option is a derivative, but the second is not because it is contingent upon a physical variable.

There are specific contractual provisions providing that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2009, our obligation is about 47 percent of the total VJO Power Contract through 2016, and represents approximately $352.1 million, on a nominal basis.

In accordance with FASB's guidance for guarantees, we are required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. With regard to the "step-up" provision in the VJO Power Contract, we must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. We believe this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power in their most recent rate applications. Despite the remote chance that such an event could occur, we estimate that our undiscounted purchase obligation would be an additional $412.7 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2010 and remained in default for the duration of the contract. In such a scenario, we would then own the power and could seek to recover our costs from the defaulting members or our retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

Total purchases from Hydro Quebec were $63.1 million in 2009, $63.7 million in 2008 and $64.9 million in 2007. Annual capacity costs decreased by $2.2 million starting November 1, 2009, which will continue for six contract years. A summary of the Hydro-Quebec actual charges for 2009 and the projected charges for the remainder of the contract are shown in the table below. Projections are based on certain assumptions including availability of the transmission system and scheduled deliveries, so actual amounts may differ (dollars in thousands, except per kWh amounts):

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

(a) Annual capacity acquired is projected to average approximately 116 MW for 2013 - 2014, 100 MW for 2015 and 19 MW for 2016.
(b) Annual load factor applies to 12-month periods beginning November 1. Calendar-year load factors may be different.

Independent Power Producers: We receive power from several Independent Power Producers ("IPPs"). These plants use water or biomass as fuel. Most of the power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Our total purchases from IPPs were $22.6 million in 2009, $26.4 million in 2008 and $22.8 million in 2007. Estimated annual purchases are expected to range from $9.9 million to $21.5 million for the years 2010 through 2014. Cost will begin to drop when a major contract obligation ends in 2012. These estimates are based on assumptions regarding average weather conditions and other factors affecting generating unit output, so actual amounts may differ.

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

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

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

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

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

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

In January 2004 DNC filed, on behalf of itself and the two minority owners, including us, a lawsuit against the DOE seeking recovery of costs related to the storage of spent nuclear fuel arising from the failure of the DOE to comply with its obligations to commence accepting such fuel in 1998. A trial commenced in May 2008. On October 15, 2008, the United States Court of Federal Claims issued a favorable decision in the case, including damages specific to Millstone Unit #3. The DOE appealed the court's decision in December 2008. On February 20, 2009, the government filed a motion seeking an indefinite stay of the briefing schedule. On March 18, 2009, the court granted the government's request to stay the appeal. On November 19, 2009, DNC filed a motion to lift the stay. The DOE opposed this motion and also asked the court to grant it an additional 45 days to file its initial brief in the appeal should the Court lift the stay. Once the stay is lifted, briefing on the appeal will take place. We continue to pay our share of the DOE Spent Fuel assessment expenses levied on actual generation and will share in recovery from the lawsuit, if any, in proportion to our ownership interest.

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

We have equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down and completely decommissioned except for the spent fuel storage at each location. Our obligations related to these plants are described in Part II, Item 8, Note 3 - Investments in Affiliates.

We also had a 35 percent ownership interest in the Vermont Yankee nuclear power plant through our equity investment in VYNPC, but the plant was sold in 2002. Our obligation for plant decommissioning costs ended when the plant was sold, except that VYNPC retained responsibility for the pre-1983 spent fuel disposal cost liability. VYNPC has a dedicated Trust Fund that meets most of the liability. Changes in the underlying interest rates that affect the earnings and the liability could cause the balance to be a surplus or deficit. Excess funds, if any, will be returned to us and must be applied to the benefit of retail

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

Performance Assurance We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $2.7 million with ISO-New England. We are required to post collateral for all net purchased power transactions in excess of _this credit limit. Additionally, we are currently selling power in the wholesale market pursuant to contracts with third parties, and are required to post collateral under certain conditions defined in the contracts.

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

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

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

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

Cleveland Avenue Property : The Cleveland Avenue property in Rutland, Vermont, was used by a predecessor to make gas from coal. Later, we sited various operations there. Due to the existence of coal tar deposits, polychlorinated biphenyl contamination and the potential for off-site migration, we conducted studies in the late 1980s and early 1990s to quantify the potential costs to remediate the site. Investigation at the site has continued, including work with the State of Vermont to develop a mutually acceptable solution. A corrective action plan was submitted to the State of Vermont on October 19, 2009 for their approval. We have reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it is adequate. The liability for site remediation is expected to range from $0.9 million to $2.3 million. As of December 31, 2009, we have accrued $1 million representing the most likely remaining cost of the remediation effort.

Brattleboro Manufactured Gas Facility : In the 1940s, we owned and operated a manufactured gas facility in Brattleboro, Vermont. We ordered a site assessment in 1999 at the request of the State of New Hampshire. In 2001, New Hampshire indicated that no further action was required, though it reserved the right to require further investigation or remedial measures. In 2002, the Vermont Agency of Natural Resources notified us that our corrective action plan for the site was approved. That plan is now in place. We have reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it is adequate. The liability for site remediation is expected to range from $0.1 million to $1.3 million. As December 31, 2009, we have accrued $0.5 million representing the most likely remaining cost of the remediation effort.

Dover, New Hampshire, Manufactured Gas Facility: In 1999, Public Service Company of New Hampshire ("PSNH") contacted us about this site. PSNH alleged that we were partially liable for cleanup, since the site was previously operated by Twin State Gas and Electric, which merged into CVPS on the same day that PSNH bought the facility. In 2002, we reached a settlement with PSNH in which certain liabilities we might have had were assigned to PSNH in return for a cash settlement paid by CVPS based on completion of PSNH's cleanup effort. As of December 31, 2009, our remaining obligation was less than $0.1 million.

The reserve for environmental matters are included as current and long-term liabilities on the Consolidated Balance Sheets and represents our best estimate of the cost to remedy issues at these sites based on available information as of the end of the reporting periods.

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

To management's knowledge, there is no pending or threatened litigation regarding other sites with the potential to cause material expense. No government agency has sought funds from us for any other study or remediation.

Leases and support agreements

Capital Leases: We had obligations under capital leases of $5.3 million at December 31, 2009 and $6.1 million at December 31, 2008. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets, and are offset by Property Under Capital Leases included in Utility plant. We account for capital leases under FASB's guidance for leases. In accordance with FASB's guidance for regulated operations and based on our ratemaking treatment, amortizations of leased assets are recorded as operating expenses on the income statement, depending on the nature and function of the leased assets. Of the $5.3 million, $5 million is related to the Phase II Hydro-Quebec ("Phase II") transmission facilities and the remaining $0.3 million is related to several five-year office and computing equipment leases.

We participated with other electric utilities in the construction of the Phase II transmission facilities in New England, which were completed at a total initial cost of $487 million. Under a 30-year support agreement relating to participation in the facilities, we agreed to pay our 5.132 percent share of Phase II costs, including capital costs plus the costs of owning and operating the facilities, over a 25-year recovery period that ends in 2015, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2020. Approximately $31 million of additional investments have been made to the Phase II transmission facilities since they were initially constructed. All costs under these agreements are recorded as transmission expense in accordance with our ratemaking policies. At December 31, 2009, the $5 million unamortized balance was comprised of $19.2 million related to our share of original costs and additional investments, offset by $14.2 million of accumulated amortization.

We also participated with other electric utilities in the construction of the Phase I Hydro-Quebec ("Phase I") transmission facilities in northeastern Vermont and northern New Hampshire, which were completed at a total cost of $140 million. Under the 30-year support agreement relating to participation in the facilities, we were obligated to pay our 4.55 percent share of Phase I capital costs over a 20-year recovery period that ended in 2006, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2016. At December 31, 2009, we had recorded accumulated amortizations of $4.9 million representing our share of the original costs associated with the Phase I transmission facility.

The Phase I and Phase II support agreements provide options for extending the agreements an additional 20 years. Each option must be exercised two years before each agreement terminates, and the transmission facilities for Phase I and Phase II must operate simultaneously for the interconnection to operate, therefore both agreements would need to be extended to be operative. Future annual payments relating to the Phase I and Phase II transmission facilities are expected to decline from $3.2 million in 2010 to $2 million in 2016. If we elect to extend both agreements, annual payments are expected to increase during the renewal terms. Approximately $0.5 million of the annual costs are currently reimbursed to us pursuant to the New England Power Pool Open Access Transmission Tariff.

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

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

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

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

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

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

At December 31, 2009, future minimum rental payments required under non-cancelable operating leases are expected to total $7.0 million, consisting of $1.8 million in 2010 and 2011, $1.3 million in 2012, $1.1 million in 2013, $0.7 million in 2014 and $0.3 million thereafter.

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

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

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

Catamount Indemnifications On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). Under the terms of the agreements with Catamount and Diamond Castle, we agreed to indemnify them, and certain of their respective affiliates, in respect of a breach of certain representations and warranties and covenants, most of which ended June 30, 2007, except certain items that customarily survive indefinitely. Indemnification is subject to a $1.5 million deductible and a $15 million cap, excluding certain customary items. Environmental representations are subject to the deductible and the cap, and such environmental representations for only two of Catamount's underlying energy projects survived beyond June 30, 2007. Our estimated "maximum potential" amount of future payments related to these indemnifications is limited to $15 million. We have not recorded any liability related to these indemnifications.

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

Appropriated Retained Earnings Major hydroelectric project licenses provide that after an initial 20-year period, a portion of the earnings of such project in excess of a specified rate of return is to be set aside in appropriated retained earnings in compliance with FERC Order No. 5, issued in 1978. Appropriated retained earnings included in retained earnings on the Consolidated Balance Sheets were $0.8 million at December 31, 2009 and 2008.

NOTE 18 - SEGMENT REPORTING

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

The accounting policies of operating segments are the same as those described in Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies. All segment operations are managed centrally by CV - VT. Segment profit or loss is based on profit or loss from continuing operations after income taxes and preferred stock dividends. Other Companies are below the quantitative thresholds individually and in the aggregate. Inter-segment revenues are excluded from the table below and are $0.3 million in 2009 and 2008 and less than $0.1 million for 2007. Financial information follows (dollars in thousands):

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

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

(a) Includes net deferral and amortization of nuclear replacement energy and maintenance costs, and amortization of regulatory assets and liabilities. These items are included in Purchased Power and Other Operation, respectively, on the Consolidated Statements of Income. Also includes capital lease amortizations.
(b) Included in Other Income on the Consolidated Statements of Income.
(c) Construction and plant expenditures for Other Companies are included in other investing activities on the Consolidated Statements of Cash Flows.

NOTE 19 - UNAUDITED QUARTERLY FINANCIAL INFORMATION

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

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

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

NOTE 20 - SUBSEQUENT EVENTS

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

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

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, 2009. Based on this evaluation, our Chief Executive Officer and Principal Financial and Accounting Officer concluded that, as of December 31, 2009, the company's disclosure controls and procedures are effective.

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

Under the supervision of our Chief Executive Officer and Principal Financial and Accounting Officer, and with participation of management, we assessed the effectiveness of the company's internal control over financial reporting based on the framework established in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, we have concluded that the company's internal control over financial reporting was effective as of December 31, 2009.

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

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

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule as of and for the year ended December 31, 2009 of the Company and our report dated March 12, 2010, which report expresses an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule and refers to the reports of other auditors (which as to Velco included an explanatory paragraph concerning a change in accounting for non-controlling interests).

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 12, 2010

Item 9B. Other Information
None

PART III

Item 10. Directors, Executive Officers and Corporate Governance.
The information required by this item is incorporated herein by reference to the section entitled "Director Elections" of the Proxy Statement of the Company for the 2010 Annual Meeting of Stockholders. The Executive Officers information is listed under Part I, Item 1. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010.

Item 11. Executive Compensation.
The information required by this item is incorporated herein by reference to the section entitled "Summary Compensation Table" of the Proxy Statement of the Company for the 2010 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchan Commission pursuant to Regulation 14A on or about March 25, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.
The information required by this item related to security ownership of certain beneficial owners is incorporated herein by reference to the section entitled "Security Ownership of Certain Beneficial Owners and Management" of the Proxy Statement of the Company for the 2010 Annual Meeti of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010. The Equity Compensation Plan Information is shown in the table below.

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

Item 13. Certain Relationships and Related Transactions, and Director Independence.
The information required by this item is incorporated herein by reference to the sections entitled "Certain Relationships and Related Transactions" and "Board Independence" of the Proxy Statement of the Company for the 2010 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010.

Item 14. Principal Accounting Fees and Services.
The information required by this item is incorporated herein by reference to the sections entitled "Services Performed by the Independent Registered Public Accountants" and "Independent Registered Public Accountant Fees" of the Proxy Statement of the Company for the 2010 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 25, 2010.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

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

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

* - Filed herewith.

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

Exhibit 3 Articles of Incorporation and By-laws

3-1 By-laws, as amended February 9, 2010. (Exhibit 99.2, Current Report on Form 8-K Filed February 16, 2010, File No. 1-8222)

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

3-2.1 Articles of Association, as amended February 17, 2010. (Exhibit No. 3-2.1, Current Report on Form 8-K Filed February 16, 2010, File No. 1-8222)

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

Incorporated herein by reference:

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

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

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

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

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

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

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

4-8 Bond Purchase Agreement, dated as of May 15, 2008, among the Company and the purchasers listed on Schedule A thereto. (Exhibit 4-8, Current Report on Form 8-K Filed May 15, 2008, File No. 1-8222)

Exhibit 10 Material Contracts (* Denotes filed herewith)

Incorporated herein by reference:

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

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

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

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

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

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

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

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

10.3.1 Copies of Amendments dated September 7, 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)

EXECUTIVE COMPENSATION PLANS AND ARRANGEMENTS

A 10.1 Directors' Supplemental Deferred Compensation Plan dated November 4, 1985. (Exhibit 10-188, 1988 Form 10-K, File No. 1-8222)

A 10.1.1 Amendment dated October 2, 1995. (Exhibit 10.72.1, 1995 Form 10-K, File No. 1-8222)

A 10.2 Directors' Supplemental Deferred Compensation Plan dated January 1, 1990 (Exhibit 10.80, 1993 Form 10-K, File No. 1-8222)

A 10.2.1 Amendment dated October 2, 1995. (Exhibit No. 10.80.1, 1995 Form 10-K, File No. 1-8222)

A 10.3 Officers' Supplemental Retirement and Deferred Compensation Plan, Amended and Restated August 4, 2008, With an Effective Dated of January 1, 2008. (Exhibit A 10.3.1, Form 10-Q, June 30, 2008, File No. 1-8222)

A 10.4 1997 Stock Option Plan for Key Employees (Exhibit 4.3 to Registration Statement, Registration 333-57001)

A 10.5 Form of Change In Control Agreement to Become Effective April 2009. (Exhibit A 10.5.2, Form 10-Q, March 31, 2008, File No. 1-8222)

A 10.6 2000 Stock Option Plan for Key Employees. (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 28, 2000, File No. 1-8222) - (Exhibit A 10.95, September 30, 2006 Form 10-Q, File No. 1-8222)

A 10.7 Deferred Compensation Plan for Officers and Directors of Central Vermont Public Service Corporation, Amended and Restated Effective August 4, 2008, With An Effective Date of January 1, 2005. (Exhibit A 10.7.1, Form 10-Q, June 30, 2008, File No. 1-8222)

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

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

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

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

A 10.12 Form of Central Vermont Public Service Performance Share Agreement Pursuant to the Performance Share Incentive Plan. (Exhibit A 10.101, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.13 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2002 Long-Term Incentive Plan. (Exhibit A 10.102, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.14 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2000 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.103, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.15 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 1997 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.104, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.16 Form of Indemnity Agreement between Directors and Executive Officers and Central Vermont Public Service Corporation. (Exhibit A 10.105, 2004 Form 10-K, File No. 1-8222)

A 10.17 Management Incentive Plan, Effective as of January 1, 2010. (Exhibit A 10.16, Current Report on Form 8-K Filed March 5, 2010, File No. 1-8222)

A - Compensation related plan, contract, or arrangement.

12 Statements Regarding Computation of Ratios

* 12.1 Statements Regarding Computation of Ratios

21 Subsidiaries of the Registrant

* 21.1 List of Subsidiaries of Registrant

23 Consent of Independent Registered Public Accounting Firm

* 23.1 Consent of Independent Registered Public Accounting Firm (D&T)

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

* 23.3 Consent of Independent Registered Public Accounting Firm (KPMG - VT Transco)

24 Power of Attorney

* 24.1 Power of Attorney executed by Directors and Officers of Company

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

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

* 32.1 Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* 32.2 Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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

* 99.2 Financial Statements of Vermont Transco LLC.

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.

CEN TRAL VERMONT PUBLIC SERVICE CORPORATION
Schedule II - Valuation and Qualifying Accounts
For the Years Ended December 31

		Additions				
	Balance at beginning of year	Charged to cost and expenses	Charged to other accounts		Deductions		Balance at end of year
2009							
Reserves deducted from assets to which they apply:							
			$ 107,521	(1)			
			$ 500,777	(2)			
			$ 222,754	(4)			
Reserve for uncollectible accounts receivable	$ 2,183,600	3,078,816	$ 831,052		$ 2,516,241	(3)	$ 3,577,227
Reserves shown separately:							
Environmental Reserve	$ 1,731,551				$ 166,171		$ 1,565,380
2008							
Reserves deducted from assets to which they apply:							
			$ 112,413	(1)			
			$ 474,398	(2)			
Reserve for uncollectible accounts receivable	$ 1,751,069	$ 2,472,997	$ 586,811		$ 2,627,277	(3)	$ 2,183,600
Reserve for uncollectible accounts receivable - affiliates	$ 47,848				$ 47,848		$ 0
Reserves shown separately:							
Environmental Reserve	$ 1,917,674				$ 186,123		$ 1,731,551
2007							
Reserves deducted from assets to which they apply:							
			$ 127,125	(1)			
			$ 405,882	(2)			
Reserve for uncollectible accounts receivable	$ 1,706,747	$ 2,412,498	$ 533,007		$ 2,901,183	(3)	$ 1,751,069
Reserve for uncollectible accounts receivable - affiliates	$ 47,848						$ 47,848
Reserves shown separately:							
Environmental Reserve	$ 2,076,282				$ 158,608		$ 1,917,674

Notes:

(1) Amount collected from collection agencies

(2) Collections of accounts previously written off

(3) Uncollectible accounts written off

(4) Amounts charged

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
(Registrant)

By: /s/ Pamela J. Keefe
Pamela J. Keefe
Senior Vice President, Chief Financial Officer, and Treasurer

March 15, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 15, 2010.

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

By: /s/ Pamela J. Keefe
(Pamela J. Keefe)
Attorney-in-Fact for each of the persons indicated.

* Such signature has been affixed pursuant to a Power of Attorney filed as an exhibit hereto and incorporated herein by reference thereto.

EXHIBIT 12.1

Central Vermont Public Service Corporation
Computation of Ratio of Earnings to Fixed Charges
For the Years Ended December 31
(dollars in thousands)

	2009	2008	2007	2006	2005(a)
Earnings, as defined by S-K 503(d):					
Pre-tax income from continuing operations	$ 31,423	$ 27,125	$ 22,553	$ 28,107	$ (672)
Plus: distributed income	10,695	10,694	4,894	2,146	1,938
Less: equity in earnings	(17,472)	(16,264)	(6,430)	(3,240)	(1,869)
Less: interest capitalized	(65)	(105)	(150)	(102)	(79)
Less: preference security dividends, as defined	(558)	(613)	(525)	(572)	(624)
Plus: fixed charges, as below	12,870	13,331	10,371	9,917	11,161
Total Earnings, as defined	36,893	$ 34,168	$ 30,713	$ 36,256	$ 9,855
Fixed charges, as defined:					
Interest on debt	$ 11,715	$ 11,648	$ 8,490	$ 8,271	$ 9,519
FIN 48 interest	(127)	39	51	0	0
Imputed interest in rental charges	724	1,031	1,305	1,074	1,018
Preferred dividends, as defined	558	613	525	572	624
Total fixed charges, as defined	12,870	$ 13,331	$ 10,371	$ 9,917	$ 11,161
Ratio of Earnings to Fixed Charges	**2.87**	**2.56**	**2.96**	**3.66**	**0.88**

(a) Reflects Catamount Energy Corporation as discontinued operations.

EXHIBIT 21.1

Subsidiaries of the Registrant

	State in Which Incorporated
Vermont Electric Power Company, Inc. (a)	Vermont
Vermont Transco LLC (a)	Vermont
Vermont Yankee Nuclear Power Corporation	Vermont
C.V. Realty, Inc. (b)	Vermont
Central Vermont Public Service Corporation - East Barnet Hydroelectric, Inc. (b)	Vermont
Custom Investment Corporation (b)	Vermont
Catamount Resources Corporation (b)	Vermont
Eversant Corporation (b) (c)	Vermont

(a) Separate financial statements will be filed under Regulation S-X 3-09, which sets forth the requirement for filing separate financial statements of subsidiaries not consolidated. The investments in Vermont Electric Power Company Inc. and Vermont Transco LLC meet certain 'significance' tests pursuant to Rule 3-09 of SEC Regulation S-X in 2009.

(b) Included in consolidated financial statements

(c) Eversant Corporation has one wholly owned subsidiary operating in the United States.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-141681, 333-151019, and 333-162979 each on Form S-3 and Registration Statement No. 333-152872 on Form S-8 of our reports dated March 12, 2010, relating to the consolidated financial statements and consolidated financial statement schedule of Central Vermont Public Service Corporation and subsidiaries ("the Company"), which report expresses an unqualified opinion and refers to the reports of other auditors (which as to Velco included an explanatory paragraph concerning a change in accounting for non-controlling interests) and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Central Vermont Public Service Corporation for the year ended December 31, 2009.

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 12, 2010

EXHIBIT 23.2

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Vermont Electric Power Company, Inc.:

We consent to the incorporation by reference in the registration statement (Nos. 333-141681, 333-151019 and 333-162979) on Form S-3 and the registration statement (No. 333-152872) on Form S-8 of Central Vermont Public Service Corporation of our report dated March 8, 2010, with respect to the consolidated balance sheets of Vermont Electric Power Company, Inc. and subsidiary as of December 31, 2009 and 2008, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2009, which report appears in the December 31, 2009 annual report on Form 10-K of Central Vermont Public Service Corporation.

Our report on the consolidated financial statements of Vermont Electric Power Company, Inc. and subsidiary, refers to the adoption of FASB ASC 810, *Noncontrolling Interest in Consolidated Financial Statements—an amendment of ARB No. 51* , as of January 1, 2009.

/s/ KPMG LLP

Burlington, Vermont
March 12, 2010

Vt. Reg. No. 92-0000241

EXHIBIT 23.3

Consent of Independent Registered Public Accounting Firm

The Stockholder and Board of Directors
Vermont Electric Power Company, Inc. as Manager of Vermont Transco LLC:

We consent to the incorporation by reference in the registration statement (Nos. 333-141681, 333-151019 and 333-162979) on Form S-3 and the registration statement (No. 333-152872) on Form S-8 of Central Vermont Public Service Corporation of our report dated March 8, 2010, with respect to the balance sheets of Vermont Transco LLC as of December 31, 2009 and 2008, and the related statements of income, changes in members' equity, and cash flows for each of the years in the three-year period ended December 31, 2009, which report appears in the December 31, 2009 annual report on Form 10-K of Central Vermont Public Service Corporation.

/s/ KPMG LLP

Burlington, Vermont
March 12, 2010

Vt. Reg. No. 92-0000241

EXHIBIT 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned Chief Executive Officer and Vice President, Chief Financial Officer, and Treasurer and the undersigned Directors of Central Vermont Public Service Corporation, a Vermont Corporation, which corporation proposes to file with the Securities and Exchange Commission an Annual Report on Form 10-K for the year ended December 31, 2009, under the Securities Exchange Act of 1934, as amended, does each for himself/herself and not for one another, hereby constitute and appoint Robert H. Young and Pamela J. Keefe and each of them, his/her true and lawful attorneys, in his/her name, place and stead, to sign his/her name to said proposed Annual Report on Form 10-K and any and all amendments thereto, and to cause the same to be filed with the Securities and Exchange Commission, it being intended to grant and hereby granting to said individuals, and each of them, full power and authority to do and perform any act and thing necessary and proper to be done in the premises as fully and to all intents and purposes as the undersigned could do regarding the preparation, execution, filing of Form 10-K.

IN WITNESS WHEREOF, each of the undersigned has hereunto set their hand as of the 11 th day of January, 2010.

/s/ Robert H. Young
Robert H. Young
President and Chief Executive Officer
Chairman of the Board, and Director

/s/ Pamela J. Keefe
Pamela J. Keefe
Senior Vice President, Chief Financial Officer, and Treasurer

/s/ Robert L. Barnett
Robert L. Barnett, Director

/s/ Robert G. Clarke
Robert G. Clarke, Director

/s/ John M. Goodrich
John M. Goodrich, Director

/s/ William R. Sayre
William R. Sayre, Director

/s/ Janice L. Scites
Janice L. Scites, Director

/s/ William J. Stenger
William J. Stenger, Director

/s/ Douglas J. Wacek
Douglas J. Wacek, Director

EXHIBIT 31.1

ANNUAL CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER REQUIRED BY SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert H. Young, certify that:

1. I have reviewed this annual report on Form 10-K of Central Vermont Public Service Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's 4 th fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2010

/s/ Robert H. Young

Robert H. Young
Chief Executive Officer

EXHIBIT 31.2

ANNUAL CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER REQUIRED BY SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Pamela J. Keefe, certify that:

1. I have reviewed this annual report on Form 10-K of Central Vermont Public Service Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's 4 th fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2010

/s/ Pamela J. Keefe

Pamela J. Keefe
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Central Vermont Public Service Corporation (the "Company") on Form 10-K for the period ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I Robert H. Young, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge and belief:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert H. Young

Robert H. Young
Chief Executive Officer
March 15, 2010

A signed original of this written statement required by Section 906 has been provided to Central Vermont Public Service Corporation ("CVPS") and will be retained by CVPS and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Central Vermont Public Service Corporation (the "Company") on Form 10-K for the period ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I Pamela J. Keefe, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge and belief:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Pamela J. Keefe

Pamela J. Keefe
Chief Financial Officer
March 15, 2010

A signed original of this written statement required by Section 906 has been provided to Central Vermont Public Service Corporation ("CVPS") and will be retained by CVPS and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 99.1

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Consolidated Financial Statements

December 31, 2009 and 2008

(With Report of Independent Registered Public Accounting Firm Thereon)

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

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Report of Independent Registered Public Accounting Firm

The Stockholder and Board of Directors
Vermont Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of Vermont Electric Power Company, Inc. and subsidiary as of December 31, 2009 and 2008, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Companies' management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Vermont Electric Power Company, Inc. and subsidiary as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period end December 31, 2009 in conformity with U.S. generally accepted accounting principles.

As discussed in notes 1(b) and 7 to the consolidated financial statements, the Company adopted FASB ASC 810, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* , as of January 1, 2009.

/s/ KPMG LLP

March 8, 2010

Vt. Reg. No. 92-0000241

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Consolidated Balance Sheets

December 31, 2009 and 2008

Assets	**2009**	**2008**
Utility plant (notes 2 and 3)	$ 727,984,046	568,692,579
Less accumulated depreciation and amortization	(98,071,916)	(89,777,198)
Net utility plant	629,912,130	478,915,381
Investment in Vermont Electric Transmission Company, Inc. (note 9)	502,159	488,546
Current assets:		
Cash	40,026,479	466,849
Bond sinking fund deposits	526,000	490,000
Bond interest deposits	4,573,388	2,985,911
Accounts receivable:		
Affiliated companies	14,040,604	13,749,601
Other	7,953,242	7,183,366
Note receivable – related party (note 9)	925,000	700,000
Materials and supplies	6,248,996	6,684,808
Income tax receivable	169,995	650,941
Prepaids and other assets	1,792,918	1,776,088
Total current assets	76,256,622	34,687,564
Regulatory and other assets:		
Regulatory assets	8,919,131	11,945,066
Unamortized debt expense, net	2,712,165	1,799,001
Cash surrender value of life insurance policies (note 8)	3,487,486	3,001,152
Deferred project costs and other	3,654,783	165,978
Total regulatory and other assets	18,773,565	16,911,197
Total assets	$ 725,444,476	531,002,688

(Continued)

Capitalization and Liabilities	2009	2008
Capitalization:		
Stockholders' equity:		
Class B common stock; $100 par value per share. Authorized 430,000 shares; issued and outstanding 219,977 shares	$ 21,997,700	21,997,700
Class C common stock; $100 par value per share. Authorized 20,000 shares; issued and outstanding 19,901 shares	1,990,100	1,990,100
Retained earnings	1,192,858	292,206
	25,180,658	24,280,006
Class C preferred stock, $100 par value per share. Authorized 125,000 shares; 97,068 shares issued and outstanding (note 6)	145,602	145,602
	25,326,260	24,425,608
First mortgage bonds, net of current maturities (note 3)	329,093,000	196,254,000
Other long-term debt, net of current maturities (note 3)	—	152,115
Total capitalization attributable to VELCO	354,419,260	220,831,723
Equity interest of noncontrolling members in Vermont Transco LLC (note 7)	295,401,424	222,409,012
Total capitalization	649,820,684	443,240,735
Commitments and contingencies (notes 8, 13 and 15)		
Current liabilities:		
Current maturities of long-term obligations (note 3)	2,313,115	2,306,121
Notes payable to bank (note 4)	—	20,857,520
Bank overdraft	2,975,031	1,594,738
Accounts payable:		
Affiliated companies	796,981	587,047
Other	21,971,950	20,167,302
Accrued interest on bonds	4,573,254	3,001,260
Accrued taxes	468,156	501,316
Accrued construction expenses	9,961,114	11,589,929
Accrued expenses	5,706,505	3,120,194
Total current liabilities	48,766,106	63,725,427
Reserves and deferred credits:		
Deferred cost of removal liabilities (note 11)	3,287,144	2,135,304
Deferred tax liabilities (note 5)	11,425,141	9,464,587
Deferred compensation (note 8)	5,769,612	5,443,855
Deferred income and other	1,156,958	—
Accrued pension and postretirement liabilities (note 8)	5,218,831	6,992,780
Total reserves and deferred credits	26,857,686	24,036,526
Total capitalization and liabilities	$ 725,444,476	531,002,688

See accompanying notes to consolidated financial statements

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Consolidated Statements of Income

Years ended December 31, 2009, 2008 and 2007

	2009	2008	2007
Operating revenues:			
Transmission revenues	$ 90,649,734	73,575,150	49,903,641
Sales of power	510,823	460,479	445,038
Rent of transmission facilities to others	2,435,380	1,624,487	1,562,284
Total operating revenues	93,595,937	75,660,116	51,910,963
Operating expenses:			
Transmission expenses:			
Operations	3,369,434	3,396,212	2,577,857
Maintenance	5,625,653	4,854,048	4,322,067
Rents	41,705	42,602	39,862
Purchased power	510,823	460,479	445,038
Administrative and general expenses	7,718,153	8,672,359	8,913,458
Depreciation and amortization	13,942,091	10,740,097	8,268,529
Taxes other than income	10,485,062	7,405,913	5,422,076
Total operating expenses	41,692,921	35,571,710	29,988,887
Operating income	51,903,016	40,088,406	21,922,076
Other income:			
Interest	239,474	111,326	103,201
Equity in earnings of subsidiary (note 9)	29,457	41,096	50,832
Income before interest and other expense, noncontrolling interest and income tax	52,171,947	40,240,828	22,076,109
Interest and other expense:			
Interest on first mortgage bonds	13,477,726	11,994,760	11,228,262
Other interest	1,495,343	572,468	3,137,004
Amortization of debt expense	101,560	97,788	95,261
Other	12,708	27,602	27,726
Allowance for borrowed funds used during construction	(2,151,956)	(3,256,055)	(4,457,120)
Allowance for equity funds during construction	(2,977,719)	(4,884,082)	(1,910,194)
Net interest and other expense	9,957,662	4,552,481	8,120,939
Income before noncontrolling interest and income tax	42,214,285	35,688,347	13,955,170
Income tax (note 5)	2,337,632	2,174,944	1,660,965
Net income	39,876,653	33,513,403	12,294,205
Noncontrolling interest in the income of Vermont Transco LLC (note 7)	36,201,872	30,712,296	9,483,361
Net income attributable to VELCO	$ 3,674,781	2,801,107	2,810,844

See accompanying notes to consolidated financial statements.

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Consolidated Statements of Stockholders' Equity

Years ended December 31, 2009, 2008 and 2007

	Common stock		Preferred stock	Retained earnings	Total stockholders' equity
	Class B	Class C			
Balances at December 31, 2006	$ 21,997,700	1,990,100	145,602	229,481	24,362,883
Net income, attributable to VELCO	—	—	—	2,810,844	2,810,844
Dividends declared and paid	—	—	—	(2,774,127)	(2,774,127)
Balances at December 31, 2007	21,997,700	1,990,100	145,602	266,198	24,399,600
Net income, attributable to VELCO	—	—	—	2,801,107	2,801,107
Dividends declared and paid	—	—	—	(2,775,099)	(2,775,099)
Balances at December 31, 2008	21,997,700	1,990,100	145,602	292,206	24,425,608
Net income, attributable to VELCO	—	—	—	3,674,781	3,674,781
Dividends declared and paid	—	—	—	(2,774,129)	(2,774,129)
Balances at December 31, 2009	$ 21,997,700	1,990,100	145,602	1,192,858	25,326,260

See accompanying notes to consolidated financial statements.

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Consolidated Statements of Cash Flows

Years ended December 31, 2009, 2008 and 2007

	2009	2008	2007
Cash flows from operating activities:			
Net income	39,876,653	33,513,403	12,294,205
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	13,370,741	10,168,747	7,691,370
Amortization of regulatory assets	571,350	571,350	577,159
Amortization of debt expense	101,560	97,788	95,261
Deferred income tax expense	1,318,778	2,235,745	1,089,386
Equity in earnings of subsidiary	(29,457)	(41,096)	(50,832)
Dividends from subsidiary	15,844	15,780	15,938
Changes in assets and liabilities:			
Accounts receivable	(1,060,879)	(280,425)	(2,822,531)
Materials and supplies	435,812	(957,340)	4,381,043
Income tax receivable	480,946	103,861	(562,985)
Regulatory assets	—	—	(27,875)
Accounts payable	3,305,420	3,542,156	(10,707,745)
Employee benefit plan funding	680,635	(363,907)	(30,951)
Deferred compensation	325,757	(108,961)	(157,584)
Other assets and liabilities	830,768	141,604	(1,376,794)
Net cash provided by operating activities	60,223,928	48,638,705	10,407,065
Cash flows from investing activities:			
Change in bond sinking fund deposits	(36,000)	(33,000)	(32,000)
Advances to related party	(225,000)	150,000	(850,000)
Capital expenditures, net	(166,135,303)	(98,712,016)	(115,850,406)
Change in cash surrender value of life insurance policies	(486,334)	588,770	(308,005)
Net cash used in investing activities	(166,882,637)	(98,006,246)	(117,040,411)
Cash flows from financing activities:			
Change in bank overdraft	1,380,293	(218,324)	1,813,062
Proceeds from bond issuance	135,000,000	—	80,000,000
Repayment of bonds	(2,014,000)	(1,877,000)	(1,748,000)
Debt issue costs	(1,014,724)	(47,370)	(357,675)
(Repayments of) proceeds from notes payable to bank	(20,857,520)	20,857,520	(61,470,000)
Repayment of other long-term debt	(292,121)	(400,682)	(688,476)
Issuance of VT Transco membership units	60,047,790	38,683,000	113,750,000
Distribution of VT Transco earnings to noncontrolling members	(23,257,250)	(19,578,060)	(7,110,796)
Issuance of Class B common stock	—	—	—
Cash dividends on common stock	(2,758,597)	(2,758,597)	(2,758,597)
Cash dividends on preferred stock	(15,532)	(16,502)	(15,530)
Net cash provided by financing activities	146,218,339	34,643,985	121,413,988
Net increase (decrease) in cash	39,559,630	(14,723,556)	14,780,642
Cash, beginning of year	466,849	15,190,405	409,763
Cash, end of year	$ 40,026,479	466,849	15,190,405

(Continued)

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Consolidated Statements of Cash Flows

Years ended December 31, 2009, 2008 and 2007

	2009	2008	2007
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest, net of amounts capitalized	7,830,970	9,392,394	8,300,276
Cash (refund) paid for income taxes	(49,138)	500,296	1,210,550

Noncash operating activities:

The Company recorded an unfunded defined benefit pension and other postretirement obligation of $5,218,831 and $6,992,780 at December 31, 2009 and 2008, respectively, and a defined benefit pension and other postretirement regulatory asset of $4,668,246 and $7,142,831 at December 31, 2009 and 2008, respectively.

In 2009, 2008, and 2007 the Company utilized alternative minimum tax credits and recorded an income tax receivable of $641,776, $(156,308), and $0 respectively.

Noncash investing activities:

In 2009, 2008, and 2007, the Company recorded accrued construction expenses of $(337,977), and $8,698,749, and $7,839,770, respectively.

See accompanying notes to consolidated financial statements.

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

(1) Summary of Significant Accounting Principles

(a) Description of Business

The consolidated financial statements of Vermont Electric Power Company, Inc. (VELCO or the Company) include the accounts of Vermont Transco LLC (VT Transco) and VELCO. The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) as to rates, terms of service and financing and by state regulatory commissions as to other aspects of business, including the construction of electric transmission assets.

VELCO owned and operated an electric power transmission system in the State of Vermont. VELCO had transmission contracts with the State of Vermont, acting by and through the Vermont Department of Public Service, and with all of the electric utilities providing service in the State of Vermont. These transmission contracts have been reviewed and approved by the FERC. Additionally, VELCO has an agreement for single unit power purchases of electricity, which it resells at cost to one of its stockholders in the State of Vermont.

On June 30, 2006, VELCO transferred substantially all of its electric transmission assets, along with the associated contracts, to VT Transco, in exchange for Class A Member units, and the assumption of VELCO's long term debt and other liabilities. In addition, VELCO entered into a Management Services Agreement with Vermont Transco to serve as the Manager of VT Transco. This agreement provides for VT Transco to reimburse VELCO for all of its costs in fulfilling its responsibilities as the Manager of VT Transco.

VELCO, through its wholly owned subsidiary, Vermont Electric Transmission Company, Inc. (VETCO) (see note 9), constructed and maintains the Vermont portion of a transmission line used to transmit power purchased by the New England Power Pool on behalf of New England electric utilities from Hydro Quebec, a Canadian utility. To assist VELCO in making its initial capital contribution to VETCO, the participating Vermont electric utilities purchased all of the shares of VELCO's Class C preferred stock.

VELCO's common and preferred stock are owned by various Vermont utilities. Central Vermont Public Service Corporation (CVPS) owns 48% of VELCO's Class B and 31% of its Class C common stock and 47% of its Class C preferred stock.

VELCO also has agreements with various stockholders and other Vermont utilities to act as agent in order to provide a single entity that can accumulate costs related to the combined utilities' participation in certain joint projects. VELCO bills these costs, along with any direct costs incurred, to the participating Vermont utilities in accordance with each participant's obligations. These agency transactions are not reflected as part of VELCO's operations; however, operating expenses may be indirectly impacted from year to year, depending on the significance and nature of the activities performed by VELCO.

(b) Consolidation

The accompanying consolidated financial statements include the accounts of VELCO and VT Transco as VELCO is the primary beneficiary and controls the financial and operating policies of VT Transco. Ownership interests of members other than the Company in the equity of VT Transco are

(Continued)

presented as a component of equity in the consolidated balance sheets as noncontrolling interests in the caption labeled "Equity Interest of Noncontrolling Members in VT Transco LLC." The share of members other than the Company in the income of VT Transco is deducted in determining the Company's consolidated net income. Inter-company balances and transactions have been eliminated in consolidation.

(c) Regulatory Accounting

The Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit specific incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when it is probable that such costs will be recovered in customer rates. Incurred costs are deferred as regulatory assets when the Company concludes that it is probable future revenues will be provided to permit recovery of the previously incurred cost. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence, and legal representations. These regulatory amounts do not include the recognition of tax effects, which generally would be approximately 39%. A regulatory liability is recorded when amounts that have been recorded by the Company are likely to be refunded to customers through the rate-setting process.

On December 9, 2005, the FERC approved a filing allowing at that time VELCO, and now through its subsidiary VT Transco, to begin amortizing over a ten year period the deferred depreciation charges the Company incurred when taking depreciation under the bond sinking fund method. This regulatory asset, which accounts for the difference between depreciation reported in the consolidated financial statements and depreciation previously recovered in rates, is $2,552,332 and $2,977,721 as of December 31, 2009 and 2008, respectively.

On June 16, 2006, the FERC approved a filing allowing at the time VELCO, and now through its subsidiary VT Transco, to accumulate as a regulatory asset the costs associated with VT Transco transaction and to amortize and recover that asset over a fifteen year period to commence when the Company began operations. This regulatory asset is $1,678,553 and $1,824,514 as of December 31, 2009 and 2008, respectively.

As more fully described in note 8, the defined pension and other postretirement regulatory assets represent the unrecognized pension costs and other postretirement costs that would normally be recorded as a component of other comprehensive income. Since these amounts represent costs that are expected to be recovered in future rates, they are recorded as regulatory assets. The regulatory asset related to the plans totaled $4,688,246 and $7,142,831 at December 31, 2009 and 2008.

The Company continually assesses whether regulatory assets continue to meet the criteria for probability of future recovery. This assessment includes consideration of factors such as changes in the regulatory environment, recent rate orders to other regulated entities under the same jurisdiction. If future recovery of certain regulatory assets becomes improbable, the affected assets would be written off in the period in which such determination is made.

(Continued)

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

(d) Revenue Recognition

Electric transmission service for utilities, municipalities, municipal electric companies, electric cooperatives, and other eligible entities is provided through the Company's facilities under the ISO NE open access transmission tariff and the 1991 Vermont Transmission Agreement, both regulated by FERC. The Company charges for these services under FERC approved rates. Prior to June 30, 2006, revenue was billed monthly based on estimated cost of service plus 11.5% return on capital. The tariff specifies the general terms and conditions of service on the transmission system and the approved rates set forth the revenue to be billed monthly based on estimated cost of service plus an 11.5% return on capital for Class B and Class C shareholders prior to June 30, 2006 and 11.5% return on capital for Class A Member units and a 13.3% return on capital for Class B Member units from inception of VT Transco. The effect of unbilled revenue at the end of the accounting period represents the difference between billed and actual costs for the month of December and is $0 and $246,512 at December 31, 2009 and 2008, respectively, and is reported in other assets in the accompanying consolidated financial statements.

(e) Utility Plant

Utility plant in service is stated at cost.

Major expenditures for plant and those which substantially increase useful lives are capitalized. The Company recognizes depreciation expense as a percentage of gross transmission plant at 2.63% as of December 31, 2009, 2008 and 2007. This method is consistent with the straight line method of depreciation.

Software is recorded at cost. Amortization is recorded at straight line rates over the estimated useful life of the assets which is five years.

(f) Long-Lived Assets

Long lived assets, such as utility plant, and regulatory assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of assets may not be recoverable. If circumstances require a long lived asset be tested for possible impairment, the Company first compares undiscounted cash flows expected to be generated by an asset to the carrying value of the asset. If the carrying value of the long lived asset is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values and third party independent appraisals, as considered necessary. As long as its assets continue to be recovered through the ratemaking process, the Company believes that such impairment is unlikely.

(g) Allowance for Borrowed Funds Used During Construction (AFUDC)

Allowance for funds used during construction (AFUDC) represents the cost of borrowed and equity funds used to finance the construction of transmission assets. The portion of AFUDC attributable to borrowed funds and the cost of equity funds are included as other expense in the consolidated statements of income. AFUDC is not currently realized in cash, but is recovered in the form of

(Continued)

increased revenue collected as a result of depreciation of the property. The Company capitalized AFUDC at an average rate of 5.75%, 7.35% and 7.10% in 2009, 2008 and 2007, respectively.

(h) Materials and Supplies Inventory

Materials and supplies are stated at the lower of cost or market. Cost is determined on a weighted average basis.

(i) Unamortized Debt Expense

Costs associated with the original issuance of long term debt has been capitalized and amortized over the term of the debt using the effective interest rate method. Amortization expense amounted to $101,560, $97,788 and $95,261 in 2009, 2008 and 2007, respectively.

(j) Income Taxes

VT Transco LLC is a limited liability company that has elected to be treated as a partnership under the Internal Revenue Code and applicable state statutes. As such, it is not liable for federal or state income taxes. VT Transco's members (except certain tax exempt members) report their share of the Company's earnings, gains, losses, deductions and tax credits on their respective federal and state income tax returns. Accordingly, these consolidated financial statements include a provision for federal and state income tax expense of VELCO only.

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date.

Beginning with the adoption of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* , included in FASB ASC Subtopic 740-10, *Income Taxes—Overall* , as of January 1, 2009, the Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs. Prior to the adoption of Interpretation 48, the Company recognized the effect of income tax positions only if such positions were probable of being sustained.

The Company records interest related to unrecognized tax benefits in interest expense and penalties in administrative and general expenses.

(k) Pension and Other Postretirement Plans

The Company sponsors a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service and final average pay.

(Continued)

The Company also sponsors a defined benefit health care plan for substantially all employees. The Company measures the costs of its obligation based on its best estimate. The net periodic costs are recognized as employees render the services necessary to earn the postretirement benefits.

The Company adopted the measurement date provisions of FASB ASC 715-30, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* during fiscal year 2008 which required the Company to change its measurement date for plan assets and benefit obligations to December 31. The Manager adopted the measurement date provisions during fiscal year 2008, which required the Manager to change its measurement date for plan assets and benefit obligations to December 31. Prior to 2008, the Manager measured its plan assets and benefit obligations as of September 30. The total impact of the change in measurement date for both plans totaled $380,780 and was recovered in rates in 2009.

(l) Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America, requires management to make estimates and assumptions relating to the reported amounts of assets and liabilities and disclosure of contingencies at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant items subject to such estimates and assumptions include the carrying amount of utility plant, recoverability of deferred income tax assets and other regulatory assets, obligations related to employee benefits, and the assumptions used to estimate the fair value of financial instruments. The current economic environment has increased the degree of uncertainty inherent in those estimates and assumptions.

(m) Commitments and Contingencies

Liabilities for loss contingencies, arising from claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment can be reasonably estimated. Legal costs incurred are expensed as incurred.

(n) Fair Value

On January 1, 2008, the Company adopted FASB Statement No. 157, *Fair Value Measurements* , included in ASC Topic 820, *Fair Value Measurements and Disclosures* , for fair value measurements of nonfinancial items that are recognized or disclosed at fair value in the financial statements on a recurring basis. Fair value is defined 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. ASC Topic 820 also establishes a framework for measuring fair value and expands disclosures about fair value measurements.

On January 1, 2009, the Company adopted the provisions of ASC Topic 820 to fair value measurements of nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. There was no impact to the financial statements.

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(o) Recently Issued Accounting Standards

The FASB issued ASU 2009-17, Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities (FASB Statement No. 167, Amendments to FASB Interpretation No. 46(R) in 2009. ASU 2009-17, which amends the Variable Interest Entity (VIE) Subsections of ASC SubTopic 810-10, Consolidation—Overall, revises the test for determining the primary beneficiary of a VIE from a primarily quantitative risks and rewards calculation based on the VIE's expected losses and expected residual returns to a primarily qualitative analysis based on identifying the party or related-party group (if any) with (a) the power to direct the activities that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. The ASU requires kick-out rights and participating rights to be ignored in evaluating whether a variable interest holder meets the power criterion unless those rights are unilaterally exercisable by a single party or related party group. The ASU also revises the criteria for determining whether fees paid by an entity to a decision maker or another service provider are a variable interest in the entity and revises the Topic 810 scope characteristic that identifies an entity as a VIE if the equity-at-risk investors as a group do not have the right to control the entity through their equity interests to address the impact of kick-out-rights and participating rights on the analysis. Finally, the ASU adds a new requirement to reconsider whether an entity is a VIE if the holders of the equity investment at risk as a group lose the power, through the rights of those interests, to direct the activities that most significantly impact the VIE's economic performance, and requires a company to reassess on an ongoing basis whether it is deemed to be the primary beneficiary of a VIE. ASU 2009-17 is effective for periods beginning after December 15, 2009. The Company expects that the adoption of ASU 2009-17 will not have a material impact on its consolidated financial statements.

(2) Utility Plant

Utility plant consists of the following at December 31, 2009 and 2008:

	2009	2008
Land and rights of way	$ 58,577,888	32,813,905
Transmission equipment	485,271,008	429,493,138
Communications equipment	15,163,134	11,162,825
Buildings and office equipment	46,971,015	42,669,595
Construction work-in-process	122,001,001	52,553,116
	727,984,046	568,692,579
Less accumulated depreciation and amortization	98,071,916	89,777,198
	$ 629,912,130	478,915,381

Depreciation and amortization expense was $13,370,741, $10,168,747 and $7,691,370 for the years ended December 31, 2009, 2008 and 2007, respectively.

(Continued)

(3) Long Term Debt

(a) First Mortgage Bonds

The Company's First Mortgage Bonds outstanding include the following series at December 31, 2009 and 2008:

	2007	2008
Series L, 7.30% due through 2018	$ 7,412,000	8,021,000
Series N, 7.42%, due through 2012	20,813,000	21,823,000
Series O, 6.26% due through 2034	23,029,000	23,424,000
Series P, 5.72% due through 2036	30,000,000	30,000,000
Series Q, 5.59% due through 2036	35,000,000	35,000,000
Series R, 5.75% due through 2037	80,000,000	80,000,000
Series S, 4.81% due through 2029	135,000,000	—
	331,254,000	198,268,000
Less bonds to be retired within one year	2,161,000	2,014,000
	$ 329,093,000	196,254,000

In October 2009, the Company received the proceeds from the sale of its Series S First Mortgage Bonds for the principal amount of $135,000,000, which the Company used to pay down its existing line of credit.

The First Mortgage Bonds are secured by a first mortgage lien on the Company's utility plant. The bonds to be retired through principal payments within the next five years and thereafter will amount to:

Year ending December 31:	
2010	$ 2,161,000
2011	11,821,000
2012	19,789,000
2013	11,821,000
2014	13,916,000
Thereafter	271,746,000
Total	$ 331,254,000

The terms of the indenture, as supplemented, under which the First Mortgage Bonds were issued, require, among other restrictions, that the total of common equity investment and indebtedness of the Company subordinated to the First Mortgage Bonds must equal at least one third of the aggregate principal amount of the bonds outstanding or $110,418,000, at December 31, 2009. The Company believes it is in compliance with this requirement at December 31, 2009.

(Continued)

(b) Other Debt

Other debt includes notes payable of $152,115 and $444,236 at December 31, 2009 and 2008, respectively, bearing interest at 5.44%, which matures June 1, 2010. The notes are secured by a lien on certain office equipment.

(4) Notes Payable to Bank

The Company has an unsecured $120,000,000 line of credit agreement with a financial institution, reduced by certain standby letters of credit, expiring on December 27, 2010, to provide interim financing for utility plant construction. As part of this agreement, the Company agrees to pay 0.15% per annum on the daily unused line of credit amount. Average daily borrowing was $43,352,850 in 2009 at a weighted average interest rate of 2.42%. The outstanding balance at December 31, 2009 and 2008 amounted to $0 and $20,857,520, respectively.

(5) Income Taxes

Federal and state income tax expenses (benefits) for the years ended December 31, 2009, 2008 and 2007 are as follows:

	2009	2008	2007
Federal:			
Current	$ 744,661	(228,422)	461,236
Deferred	1,098,365	1,941,141	913,267
Total federal	1,843,026	1,712,719	1,374,503
State:			
Current	274,193	167,621	110,343
Deferred	220,413	294,604	176,119
Total state	494,606	462,225	286,462
Total federal and state income tax	$ 2,337,632	2,174,944	1,660,965

The difference between the actual tax provision and the “expected” tax expense for 2009, 2008 and 2007 (computed by applying the U.S. statutory corporate tax rate to earnings before taxes) is primarily attributable to the change in equity in earnings of subsidiary, state income taxes net of federal benefit, and the effects of several nondeductible items.

(Continued)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2009 and 2008 are presented below:

	2009	2008
Deferred tax assets:		
Deferred compensation	$ 1,548,140	1,530,656
Alternative minimum tax credit	—	641,776
Other	827,205	866,790
Total gross deferred tax assets	2,375,345	3,039,222
Deferred tax liabilities:		
Utility plant depreciation	(13,800,486)	(12,503,809)
Net deferred tax liability	$ (11,425,141)	(9,464,587)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Although realization is not assured, management believes it is more likely than not that the deferred tax assets will be realized through future taxable income.

The Company adopted the provisions of Interpretation 48, included in ASC Subtopic 740-10 on January 1, 2009. As a result of the implementation of ASC Subtopic 740-10, the Company did not recognize any uncertain tax positions as of December 31, 2009.

VELCO files its income tax return on a consolidated basis with VETCO. The consolidated income taxes payable are allocated between VELCO and VETCO on a separate company basis, in accordance with a tax sharing agreement. In 2009 and 2008, respectively the Company utilized $641,776 and $0 of alternative minimum tax credits (AMT) based on an income tax accounting method change which allows regular tax and AMT tax depreciation lives to be identical.

The Company adopted the provisions of Interpretation 48, included in ASC Subtopic 740-10 on January 1, 2009. The Company has concluded there are no material uncertain tax positions.

(6) Equity Transactions

Preferred Stock

The Class C preferred stock entitles stockholders to variable rate quarterly dividends but does not entitle stockholders to vote, except under certain circumstances. Quarterly dividends and a return of capital are paid to preferred stockholders in amounts substantially equivalent to the dividends and return of capital received by the Company from VETCO.

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(7) Noncontrolling Member's Equity of VT Transco

On January 1, 2009, the Company adopted FASB ASC 810, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* , which requires certain changes to the presentation of the financial statements. This amendment requires noncontrolling interests to be classified in the consolidated statements of income as part of consolidated net earnings and to include the accumulated amount of noncontrolling interests in the consolidated balance sheets as part of capitalization. The amount previously reported as net income is now presented as net income attributable to VELCO.

VT Transco's noncontrolling members include investor owned utilities, municipalities, and electric cooperatives. Each noncontrolling member was issued membership interests in VT Transco in proportion to the value of cash it contributed to the Company. A roll forward of the equity interest of noncontrolling members in VT Transco is as follows:

	Equity interest of noncontrolling members		
	2009	**2008**	**2007**
Beginning balance	$ 222,409,012	172,591,776	56,469,212
Issuance of membership units	60,047,790	38,683,000	113,750,000
Income before tax of VT Transco	36,201,872	30,712,296	9,483,361
Distributions of VT Transco income before tax	(23,257,250)	(19,578,060)	(7,110,796)
Ending balance	$ 295,401,424	222,409,012	172,591,777

Distribution of VT Transco's income before tax to noncontrolling members is at the discretion of the Company and is in proportion to each member's percentage interest in VT Transco.

(8) Pension and Other Postretirement Benefits

The Company displays the net over or under funded position of a defined benefit pension and other postretirement plan as an asset or liability, with any unrecognized prior service costs, transition obligations or gains/losses reported as a component of other comprehensive income in stockholders' equity, unless the amount will be recoverable under the accounting guidance for regulated utilities, in which case it would be recorded as a regulatory asset. As of December 31, 2009 and 2008, the Company recorded a regulatory asset of $3,908,985 and $6,142,677, respectively, an unfunded defined benefit pension obligation of $4,296,099 and $6,171,732, respectively, a postretirement healthcare obligation of $922,732 and $821,048, respectively, and related regulatory asset of $779,261 and $1,000,154, respectively.

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(a) Defined Benefit Plan

Employees of the Company hired before January 1, 2008 who meet certain age and service requirements are covered by a defined benefit pension plan. The benefits are based on years of service and levels of compensation during the five years before retirement. The Company makes annual contributions to the plan equal to the maximum amount that can be deducted for income tax purposes. The following sets forth the plan's projected benefit obligation, fair value of plan assets and funded status at December 31, 2009 and 2008:

	Pension benefits	
	2009	**2008**
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 17,053,020	13,985,144
Service cost	1,016,923	1,253,617
Interest cost	944,414	1,114,591
Actuarial loss (gain)	(1,108,509)	1,250,017
Benefits paid	(733,966)	(550,349)
Benefit obligation at end of year	17,171,882	17,053,020
Change in plan assets:		
Fair value of plan assets at beginning of year	10,881,288	12,654,874
Actual return on plan assets	1,822,461	(2,549,237)
Employer contribution	906,000	1,326,000
Benefits paid	(733,966)	(550,349)
Fair value of plan assets at end of year	12,875,783	10,881,288
Funded status	$ (4,296,099)	(6,171,732)
Accumulated benefit obligation	$ 12,575,266	12,082,659

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2009 and 2008, which are recorded as a regulatory asset, are as follows:

	2009	**2008**
Prior service cost	$ 381,660	434,136
Effect of the change in measurement date to be recovered in rates	—	265,178
Net actuarial loss	3,527,325	5,443,363
	$ 3,908,985	6,142,677

The amount of the regulatory asset expected to be recognized as a component of net periodic pension cost in 2010 is $63,711.

(Continued)

Net periodic benefit costs for the years ended December 31, 2009, 2008 and 2007 are as follows:

	Pension benefits		
	2009	2008	2007
Components of net periodic benefit cost:			
Service cost	$ 1,016,923	1,253,617	758,614
Interest cost	944,414	1,114,591	817,913
Expected return on plan assets	(1,026,169)	(1,135,735)	(825,620)
Recognized net actuarial loss	11,235	27,818	81,154
Net amortization	52,476	65,596	52,476
Net periodic benefit cost	$ 998,879	1,325,887	884,537

The actuarial assumptions used to determine the benefit obligations are as follows:

	Pension benefits		
	2009	2008	2007
Weighted average assumptions:			
Discount rate, pension expense	6.00%	6.25%	5.75%
Discount rate, projected benefit obligation	6.00	6.00	6.25
Expected return on plan assets	7.50	7.50	7.50
Rate of compensation increase	4.50	4.50	4.50

Projected benefit payments to be paid in each year from 2010 to 2014 and the aggregate benefits expected to be paid in the five years from 2015 to 2019 are as follows:

	Pension benefit payments
Fiscal year ending December 31:	
2010	$ 659,640
2011	420,294
2012	526,804
2013	599,305
2014	787,360
2015 – 2019	4,394,909
Expected contribution for next fiscal year	$ 1,000,000

(Continued)

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

The following indicates the weighted average asset allocation percentage of the fair value of total plan assets for each major type of plan asset as of December 31, 2009 and 2008:

	Fair value		Target	
Asset class	**2009**	**2008**	**2009**	**2008**
Money market	$ 1,346,097	1,344,066	10%	9%
Equities	7,704,246	6,060,580	60	68
Fixed income	3,825,440	3,476,642	30	23
Total	$ 12,875,783	10,881,288	100%	100%

The Manager's investment policy seeks to achieve sufficient growth to enable the plan to meet future benefit obligations to participants. The current asset allocation targets 65% equity and 35% fixed income, reflecting the mid to long-term nature of the liabilities associated with the plans. The primary goals in the management of plan assets are to maintain the funds purchasing power and to maximize the mid to long-term total returns within a moderate risk environment by seeking both current income and the potential for long-term growth. The current fair value of pension plan assets is $12,875,783. Plan investments held at December 31, 2009 are classified as Level 1 based on the fair value hierarchy discussed in note 12.

(b) Postretirement Plan

The Company's current postretirement benefit plan offers health care and life insurance benefits to retired employees who meet certain age and years of service eligibility requirements. Under certain circumstances, eligible retirees are required to make contributions for postretirement benefits. The Company accrues the cost of postretirement benefits during the employees' years of service. When the Company began accrual accounting for such costs in 1993, it elected to recognize previously unaccrued postretirement benefit costs, known as the transition obligation, by amortizing these costs ratably over a 20 year period. For the years ended December 31, 2009, 2008 and 2007, the Company contributed $32,141, $137,891 and $143,431 toward these benefits. The Company anticipates contributing $180,000 for these benefits in 2010.

The FERC has established certain guidelines that all FERC regulated companies, including the Company, must follow in order to recover postretirement benefit costs in rates. The guidelines generally allow for the recovery of postretirement benefits when accrued. However, these guidelines do require that all postretirement benefit costs be funded when accrued. The Company's current plan is to fund its annual postretirement benefits accrual by making deposits into a 401(h) account, a separate account established within the pension investment fund and through a Voluntary Employees' Benefit Association (VEBA). Additionally, these guidelines require the Company to advise the FERC of its plans for accruing and funding postretirement benefit costs. The Company filed its plans with the FERC in 1995, although such plans have not yet been approved by the FERC.

(Continued)

The following table sets for the plan's benefit obligations, fair value of plan assets and funded status at December 31, 2009 and 2008:

	2009	2008
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 1,594,557	1,570,138
Service cost	93,871	95,852
Interest cost	82,303	113,129
Actuarial gain	(90,981)	(28,096)
Benefits paid	(183,618)	(156,466)
Benefit obligation at end of year	1,496,132	1,594,557
Change in plan assets:		
Fair value of plan assets at beginning of year	773,509	617,810
Actual return on plan assets	83,017	(125,623)
Employer contribution, net of VEBA reimbursement	(99,508)	437,788
Benefits paid	(183,618)	(156,466)
Fair value of plan assets at end of year	573,400	773,509
Funded status	$ (922,732)	(821,048)

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2009 and 2008, which are recorded as a regulatory asset, are as follows:

	2009	2008
Change in measurement date to be recovered in rates	$ 61,145	115,602
Net actuarial loss	718,116	884,552
	$ 779,261	1,000,154

The amount of the regulatory asset expected to be recognized as a component of net periodic benefit cost in 2010 is $55,187.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1.0% increase in the trend rate would increase the postretirement accumulated benefit obligation by $11,044 and a 1.0% decrease in the trend rate would decrease the postretirement accumulated benefit obligation by $10,366 in 2009.

(Continued)

Net periodic benefit costs as of December 31, 2009, 2008 and 2007.

	Postretirement benefits		
	2009	2008	2007
Components of net periodic benefit cost:			
Service cost	$ 93,871	95,852	67,397
Interest cost	82,303	113,129	88,743
Expected return on plan assets	(40,515)	(71,111)	(42,203)
Recognized net actuarial loss	22,234	27,793	40,041
Net amortization	32,953	37,360	22,234
Net periodic benefit cost	$ 190,846	203,023	176,212

The actuarial assumptions used to determine net periodic postretirement benefit costs are as follows:

	Postretirement benefits		
	2009	2008	2007
Weighted average assumptions:			
Discount rate, postretirement expense	6.00%	6.25%	5.75%
Discount rate, projected benefit obligation	5.50	6.25	6.25
Expected return on plan assets	6.50	7.50	7.50
Rate of compensation increase	4.50	4.50	4.50

The following indicates the weighted average asset allocation percentage of the fair value of total plan assets for each major type of plan asset as of December 31, 2009 and 2008:

	Fair value		Target	
Asset class	2009	2008	2009	2008
Cash and equivalents	$ 81,442	509,682	14%	66%
Equities	491,958	263,827	86	34
Total	$ 573,400	773,509	100%	100%

The Manager's investment policy seeks to achieve sufficient growth to enable the plan to meet future benefit obligations to participants. The Current asset allocation targets 87% equity, 12% fixed income and 1% cash, reflecting the mid to long-term nature of the liabilities associated with the plans. The primary goals in the management of plan assets are to maintain the funds purchasing

(Continued)

power and to maximize the mid to long-term total returns within a moderate risk environment by seeking both current income and the potential for long-term growth. The current fair value of postretirement plan assets is $573,400. Plan investments held at December 31, 2009 are classified as Level 1 based on the fair value hierarchy discussed in note 12.

(c) Supplemental Executive Retirement Plan

The Company sponsors a nonqualified Supplemental Executive Retirement Plan to provide certain employees and former members of the Board of Directors of the Company with additional retirement income. The Company is funding the cost of the plan in part through life insurance contracts, the cash surrender value of which was $3,487,486 and $3,001,152 at December 31, 2009 and 2008, respectively. The cost of these plans, net of the increase in cash surrender value and insurance proceeds, if any, has been charged to operating expense in the accompanying consolidated statements of income. The actuarial assumptions used to determine net benefit costs under this plan were a discount rate of 5.0%, 6.00% and 5.75%, and a rate of compensation increase of 3.0% at December 31, 2009, 2008 and 2007. Aggregate benefits payable amounted to $4,673,191 and $4,393,503 at December 31, 2009 and 2008, respectively, and are included in deferred compensation in the consolidated balance sheet.

(d) Deferred Compensation

The Company has a deferred compensation plan for current and past officers and directors. Amounts deferred are at the option of the officer or director, and include annual interest on the amounts deferred. The total deferred compensation at December 31, 2009 and 2008 is $1,096,421 and $1,050,352, respectively.

(e) Defined Contribution Plan

The Company sponsors a defined contribution plan to which eligible employees may contribute part of their salaries and wages within prescribed limits. Employees are eligible to participate in this plan during their first year of employment, if the employee has attained age 18. Additional matching contributions may be made on the employees' behalf based on the results of operations. The Company contributed $378,615, $354,666 and $307,560 in 2009, 2008 and 2007, respectively.

(9) Investment in Affiliated Company

Investment in affiliated company is accounted for under the equity method and represents VELCO's 100% ownership of the common stock of Vermont Electric Transmission Company, Inc. (VETCO). VELCO reviewed the substance of VETCO to determine if it is still appropriate that the entity is not consolidated with VELCO's operations. VETCO continues to operate under support agreements in connection with the construction of the transmission line with substantially all of the New England electric utilities. These agreements require the utilities to reimburse VETCO for all of the operating and capital costs of the line on an unconditional and absolute basis. Additionally, these support agreements provide for an advisory committee made up of participants to review VETCO's operations and make recommendations on major decisions. VETCO is obligated to follow these recommendations to the extent reasonably practical. These provisions effectively restrict VELCO's control over VETCO's operations. Based on these facts, VELCO has determined that it does not have a controlling financial interest in VETCO, as VELCO is not exposed to the risks and rewards of VETCO. In addition, the support agreements effectively restrict VELCO's

(Continued)

control, therefore VELCO has not consolidated its financial information with that of VETCO and, instead, is accounting for its investment using the equity method.

VELCO owns 100% of the common stock in VETCO. VELCO's initial capital contribution was $9,999,000. VETCO pays VELCO a quarterly dividend that represents a return on investment at a rate based on market rates. In addition, a return of investment calculated to maintain equity at approximately 20% of VETCO's total capitalization is paid to VELCO quarterly. This return of equity ceased when the long–term debt was paid in full in April 2006. Through December 31, 2009, VETCO has returned to VELCO $9,850,000 of the original capital contribution. The carrying amount of the investment is $502,159 and $488,546 at December 31, 2009 and 2008, respectively.

Summarized financial information related to VETCO at December 31, 2009 and 2008 and for the years then ended is as follows:

	Balance sheet	
	2009	2008
Net utility plant in service	$ 2,318,792	2,393,670
Other assets	1,689,585	1,561,437
Total assets	$ 4,008,377	3,955,107
Other liabilities	$ 3,506,218	3,466,561
Stockholders' investment	502,159	488,546
Total liabilities and stockholders' investment	$ 4,008,377	3,955,107

	Statement of income		
	2009	2008	2007
Operating revenues	$ 1,908,177	1,552,906	2,168,615
Operating expenses	(1,864,755)	(1,495,194)	(2,081,327)
Other income (expense)	(13,965)	(16,616)	(36,456)
Net income	$ 29,457	41,096	50,832

Other Activity

VELCO has contracted with VETCO to provide VETCO with management and support services. In connection therewith, VELCO has charged VETCO $996,437 in 2009, $738,715 in 2008, and $1,106,921 in 2007, which primarily represents payroll services and insurance costs. These amounts are reflected as operating expenses in VETCO's operating results and as a decrease in expenses in VELCO's accompanying consolidated statements of income.

The Company has made available an unsecured, short term credit facility to their related party, VETCO. The facility allows for borrowings of up to $2,000,000. The balance outstanding at December 31, 2009 and 2008 was $925,000 and $700,000, respectively.

(Continued)

(10) Related Party Transactions

CVPS personnel provide the Company with certain operational, maintenance, construction, and administrative services. In addition, payments were made by the Company to CVPS for materials and supplies and insurance. These services are provided at cost and amounted to $465,075, $697,174, and $840,908 in 2009, 2008, and 2007, respectively.

Similarly, Green Mountain Power Corporation (GMP) provides the Company with certain construction, maintenance, and operational services. These services are provided at cost or as the result of a competitive bidding process and amounted to $1,775,411, $4,373,922, and $3,600,706 in 2009, 2008, and 2007, respectively.

(11) Asset Retirement Obligations

The Company continually reviews the regulations, laws, and contractual obligations to which it is party to identify situations where there are legal obligations to perform asset retirement activities. This review has identified a limited number of leases and railroad crossing agreements which obligate the Company to perform asset retirement activities upon termination. In considering how to determine the fair value of these obligations, the Company has determined that because of the limited number and limited size of the asset retirement obligations, the fair value of the obligations would not have a material impact on its consolidated financial position, results of operation and cash flows.

Deferred cost of removal represents estimated asset retirement costs recognized under ASC 410-20, that have previously been recovered from ratepayers for other than legal obligations. The Company expects, over time, to settle or recover through the rate setting process any over or under collected net cost of removal. Cost of removal included in the balance sheet totaled $3,287,144 and $2,135,304, in 2009 and 2008, respectively.

(Continued)

(12) Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2009 and 2008. Fair value is defined as the amount that would be received to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

	2009		2008	
	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:				
Cash	$ 40,026,479	40,026,479	466,849	466,849
Bond sinking fund deposits	526,000	526,000	490,000	490,000
Bond interest deposits	4,573,388	4,573,388	2,985,911	2,985,911
Accounts receivable	21,993,846	21,993,846	20,932,967	20,932,967
Notes receivable	925,000	925,000	700,000	700,000
Financial liabilities:				
Notes payable to bank	$ —	—	20,857,520	20,857,520
Accounts payable	22,768,931	22,768,931	20,754,349	20,754,349
Accrued interest on bonds	4,573,254	4,573,254	3,001,260	3,001,260
Long term debt	2,313,115	2,313,757	2,458,236	2,459,198
First mortgage bonds	329,093,000	325,414,901	196,254,000	200,555,031
Construction and other accrued expenses	15,667,619	15,667,619	14,710,123	14,710,123

The carrying amounts shown in the table are included in the consolidated balance sheets under the indicated captions.

The fair values of the financial instruments shown in the above table as of December 31, 2009 and 2008 represent management's best estimates of the amounts that would be received to sell those assets or that would be paid to transfer those liabilities in an orderly transaction between market participants at that date. Those fair value measurements maximize the use of observable inputs. However, in situations where there is little, if any, market activity for the asset or liability at the measurement date, the fair value measurement reflects the Company's own judgments about the assumptions that market participants would use in pricing the asset or liability. Those judgments are developed by the Company based on the best information available in the circumstances.

(Continued)

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

- Cash, bond sinking fund deposits, bond interest deposits, trade accounts receivable, due from related parties, notes payable to banks, accounts payable, accrued interest on bonds, and accrued expenses: The carrying amounts, at face value or cost plus accrued interest, approximates fair value because of the short term maturity of these instruments.
- Notes receivable: Because of the short-term maturity of this instrument, cost approximates fair value.
- Long-term debt and First mortgage bonds: The fair value of the Company's long-term debt is determined by discounting the future cash flows of each instrument at rates that reflect, among other things, market interest rates. At December 31, 2009 and 2008, the Company utilized Moody's long term corporate bond yield average for utility entities with an Aa rating.

Fair Value Hierarchy

The Company adopted FASB ASC 810 on January 1, 2008 for fair value measurements of financial assets and financial liabilities and for fair value measurements of nonfinancial items that are recognized or disclosed at fair value in the financials on a recurring basis. On January 1, 2009, the Company adopted the provisions of ASC Topic 820 for fair value measurements of nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. This accounting guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to measurements involving significant unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are as follows:

Level 1 : Quoted prices are available in active markets for identical assets or liabilities as of the reporting date.

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 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.

There were no financial or nonfinancial assets or liabilities reported at fair value in the December 31, 2009 or 2008 financial statements.

(Continued)

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

(13) Business and Credit Concentrations

(a) Significant Customers

Three customers, ISO New England, CVPS, and GMP individually represent 10% or more of the total accounts receivable balance at the end of the year. These customers' percentage of the total accounts receivable balance is as follows for the years ended December 31, 2009 and 2008:

	2009	2008
ISO New England	31.0%	29.2%
CVPS	28.7	28.9
GMP	22.3	22.9
	82.0%	81.0%

(b) Significant Capital Projects

The Company is in the process of performing construction projects to enhance services to its customers. These projects have been the Company's prime focus during 2009 and 2008. Costs capitalized amounted to approximately $163,000,000, $106,000,000, and $177,000,000 in 2009, 2008, and 2007, respectively, which related to projects estimated to be completed from 2008 – 2012, including: Lamoille County 115 KV Line, Southern Loop Project, East Avenue Loop, and Northwest Reliability Project. The Company has budgeted $119,000,000 for 2010 related to these projects, which will be financed through bond issuance, capital contributions, and borrowings on the line of credit.

(14) Commitments

The Company reached a settlement with the Lamoille County municipal distribution utilities, regarding cost allocations associated with the construction of a ten mile transmission line and associated substations that will benefit Lamoille County residents. Each member utility is allowed to purchase shares in VT Transco and use the arbitrage to assist in offsetting the "specific facility" costs. The specific facility charges are limited to an amount, stated in the settlement agreement, plus the difference between the member utilities interest payments on borrowed funds used to purchase VT Transco membership units and the return on those units. After a ten year specific facility period as detailed in the settlement agreement, the membership units allocated are required to be resold to all Vermont distribution utilities with any remaining shares being re-purchased by VT Transco.

(15) Subsequent Events

The Company has evaluated subsequent events from the balance sheet date through March 8, 2010, the date at which the financial statements were available to be issued, and determined there are no other items to disclose.

EXHIBIT 99.2

VERMONT TRANSCO LLC

Financial Statements

December 31, 2009 and 2008

(With Report of Independent Registered Public Accounting Firm Thereon)

VERMONT TRANSCO LLC

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Report of Independent Registered Public Accounting Firm

The Stockholder and Board of Directors
Vermont Electric Power Company, Inc. as
Manager of Vermont Transco LLC:

We have audited the accompanying balance sheets of Vermont Transco LLC as of December 31, 2009 and 2008, and the related statements of income, changes in members' equity, and cash flows for each of the years in the three-year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly we express not such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Vermont Transco LLC as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

March 8, 2010

Vt. Reg. No. 92-0000241

VERMONT TRANSCO LLC

Balance Sheets

December 31, 2009 and 2008

Assets	**2009**	**2008**
Utility plant (notes 2 and 4)	$ 727,217,713	567,926,246
Less accumulated depreciation and amortization	(97,522,547)	(89,288,784)
Net utility plant	629,695,166	478,637,462
Current assets:		
Cash	733,150	72,900
Bond sinking fund deposits	526,000	490,000
Bond interest deposits	4,573,388	2,985,911
Accounts receivable:		
Affiliated companies	1,938,667	1,122,329
Other	6,963,198	6,261,636
Due from related party (note 8)	4,628,430	4,317,277
Due from Vermont Electric Power Company, Inc. (note 1(b))	39,287,043	—
Note receivable – related party (note 8)	925,000	700,000
Note receivable – Vermont Electric Power Company, Inc. (note 8)	10,000,000	10,000,000
Materials and supplies	6,248,996	6,684,808
Prepaids and other assets	1,562,514	1,156,118
Total current assets	77,386,386	33,790,979
Regulatory and other assets:		
Regulatory assets	4,230,885	4,802,235
Unamortized debt expense, net	2,712,165	1,799,001
Deferred project costs and other	3,156,985	165,978
Total regulatory and other assets	10,100,035	6,767,214
Total assets	$ 717,181,587	519,195,655

See accompanying notes to financial statements.

VERMONT TRANSCO LLC

Balance Sheets

December 31, 2009 and 2008

Members' Equity and Liabilities	**2009**	**2008**
Capitalization:		
Members' equity (note 3)	$ 325,469,433	249,678,381
Mandatorily redeemable membership units (notes 3, 8, and 12)	10,000,000	10,000,000
First mortgage bonds, net of current maturities (note 4)	329,093,000	196,254,000
Other long-term debt, net of current maturities (note 4)	—	152,115
Total capitalization	664,562,433	456,084,496
Commitments and contingencies (notes 7, 11, and 12)		
Current liabilities:		
Bank overdraft	2,975,031	1,594,738
Current maturities of long-term obligations (note 4)	2,313,115	2,306,121
Notes payable to bank (note 5)	—	20,857,520
Accounts payable:		
Associated	1,168,310	811,020
Other	9,175,336	7,050,989
Accrued interest on bonds	4,575,485	3,001,260
Accrued construction expenses	9,961,114	11,589,929
Accrued expenses	3,917,234	1,967,211
Total current liabilities	34,085,625	49,178,788
Long-term liabilities:		
Deferred cost of removal liabilities	3,339,769	2,175,131
Deferred income	659,160	—
Due to Vermont Electric Power Company, Inc. (note 1(b))	14,534,600	11,757,240
Total liabilities	52,619,154	63,111,159
Total capitalization and liabilities	$ 717,181,587	519,195,655

See accompanying notes to financial statements.

VERMONT TRANSCO LLC

Statements of Income

Years ended December 31, 2009, 2008 and 2007

	2009	2008	2007
Operating revenues:			
Transmission revenues	$ 90,649,734	73,575,150	49,903,641
Rent of transmission facilities to others	2,435,380	1,624,487	1,562,284
	93,085,114	75,199,637	51,465,925
Operating expenses:			
Transmission expenses:			
Operations	3,369,434	3,396,212	2,577,857
Maintenance	5,625,653	4,854,048	4,322,067
Charges for transmission facilities of others	41,705	42,602	39,862
Administrative and general expenses	7,718,153	8,672,360	8,913,458
Depreciation and amortization	13,942,091	10,740,097	8,268,529
Taxes other than income	10,485,062	7,405,913	5,422,076
Total operating expenses	41,182,098	35,111,232	29,543,849
Operating income	51,903,016	40,088,405	21,922,076
Other (income) expenses:			
Interest on first mortgage bonds	13,477,726	11,994,760	11,228,262
Other interest expense	1,057,144	572,468	3,137,004
Amortization of debt expense	101,560	97,788	95,261
Other	12,712	27,602	27,726
Interest income	(239,474)	(111,327)	(103,200)
Allowance for borrowed funds used during construction	(2,151,956)	(3,256,055)	(4,457,120)
Allowance for equity funds during construction	(2,977,719)	(4,884,082)	(1,910,194)
Total other expenses, net	9,279,993	4,441,154	8,017,739
Income before tax	$ 42,623,023	35,647,251	13,904,337

See accompanying notes to financial statements.

VERMONT TRANSCO LLC

Statements of Changes in Members' Equity

Years ended December 31, 2009, 2008 and 2007

	Membership units		Members' equity	Total members' equity
	Class A	Class B		
Balances at December 31, 2006	$ 70,369,480	7,630,620	3,626,980	81,627,080
Issuance of membership units	105,765,060	7,984,940	—	113,750,000
Income before tax	—	—	13,904,337	13,904,337
Distribution of income before tax to members	—	—	(11,079,626)	(11,079,626)
Balances at December 31, 2007	$ 176,134,540	15,615,560	6,451,691	198,201,791
Membership units at December 31, 2007	17,613,454	1,561,556		
Balances at December 31, 2007	$ 176,134,540	15,615,560	6,451,691	198,201,791
Issuance of membership units	22,782,180	15,900,820	—	38,683,000
Income before tax	—	—	35,647,251	35,647,251
Distribution of income before tax to members	—	—	(22,853,661)	(22,853,661)
Balances at December 31, 2008	$ 198,916,720	31,516,380	19,245,281	249,678,381
Membership units at December 31, 2008	19,891,672	3,151,638		
Balances at December 31, 2008	$ 198,916,720	31,516,380	19,245,281	249,678,381
Issuance of membership units	44,808,770	15,239,020	—	60,047,790
Income before tax	—	—	42,623,023	42,623,023
Distribution of income before tax to members	—	—	(26,879,761)	(26,879,761)
Balances at December 31, 2009	$ 243,725,490	46,755,400	34,988,543	325,469,433
Membership units at December 31, 2009	24,372,549	4,675,540		

See accompanying notes to financial statements.

VERMONT TRANSCO LLC

Statements of Cash Flows

Years ended December 31, 2009, 2008 and 2007

	2009	2008	2007
Cash flows from operating activities:			
Net income	$ 42,623,023	35,647,251	13,904,337
Adjustments to reconcile income before tax to net cash provided by operating activities:			
Depreciation and amortization	13,370,741	10,168,747	7,691,370
Amortization of regulatory assets	571,350	571,350	577,159
Amortization of debt expense	101,560	97,788	95,261
Changes in assets and liabilities:			
Accounts receivable	(1,517,900)	(24,303)	(2,679,060)
Materials and supplies	435,812	(957,340)	4,381,043
Regulatory assets	—	—	(27,875)
Accounts payable	3,772,475	2,099,253	(8,965,121)
Due from related party	(311,153)	13,847,108	(321,116)
Other assets and liabilities	1,975,888	3,104,015	(1,494,247)
Net cash provided by operating activities	61,021,796	64,553,869	13,161,751
Cash flows from investing activities:			
Change in bond sinking fund deposits	(36,000)	(33,000)	(32,000)
Advances to related party	—	(10,000,000)	(17,664,000)
Capital expenditures, including interest capitalized	(166,183,460)	(98,870,739)	(115,881,757)
(Advances to) repayments of related party notes receivable	(225,000)	150,000	—
Net cash used in investing activities	(166,444,460)	(108,753,739)	(133,577,757)
Cash flows from financing activities:			
Change in bank overdraft	1,380,293	(218,324)	1,813,062
Proceeds from bond issuance	135,000,000	—	80,000,000
Repayment of bonds	(2,014,000)	(1,877,000)	(1,748,000)
Debt issue costs	(1,014,724)	(47,370)	(357,675)
Borrowings of notes payable to bank	—	20,857,520	—
Repayments of notes payable to bank	(20,857,520)	—	(61,470,000)
Repayment of other long-term debt	(292,121)	(400,682)	(688,476)
Due from Vermont Electric Power Company, Inc.	(39,287,043)	—	—
Issuance of membership units	60,047,790	38,683,000	113,750,000
Issuance of mandatorily redeemable membership units	—	10,000,000	—
Distribution of income before tax to members	(26,879,761)	(22,853,661)	(11,079,626)
Net cash provided by financing activities	106,082,914	44,143,483	120,219,285
Net increase (decrease) in cash	660,250	(56,387)	(196,721)
Cash, beginning of year	72,900	129,287	326,008
Cash, end of year	$ 733,150	72,900	129,287
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 7,830,970	9,392,394	8,300,276

Noncash investing activity:
In 2009, 2008, and 2007, the Company recorded accrued construction expenses of $(337,977), $(8,698,749), and $7,839,770, respectively.

See accompanying notes to financial statements.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

(1) Summary of Significant Accounting Principles

(a) Description of Business

On June 2, 2006, VT Transco LLC (the Company) was formed as a Vermont Limited Liability Company. The Company became operational effective June 30, 2006. The Company's purpose is to plan, construct, operate, own, and maintain electric transmission and related facilities to provide for an adequate and reliable transmission system that meets the needs of all users on the system and supports equal transmission access to a competitive wholesale electric energy market. The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) as to rates, terms of service and financing and by state regulatory commissions as to other aspects of business, including the construction of electric transmission assets.

The largest owners of membership units are as follows:

	2009	2008
VELCO	12%	14%
Central Vermont Public Service Corporation (CVPS)	34	33
Green Mountain Power Company (GMP)	28	29

VELCO has transmission contracts with the State of Vermont, acting by and through the Vermont Department of Public Service, and with all of the electric utilities providing service in the State of Vermont. As part of the Transfer and Assumption Agreement, these transmission contracts were legally transferred to the Company effective June 30, 2006. These transmission contracts have been reviewed and approved by the FERC. The transmission contracts provide, among other things, for the Company to earn an annual return equal to 11.5% of outstanding Class A Member units and an annual return equal to 13.3% of outstanding Class B Member units. These earnings, at the discretion of VELCO are distributed quarterly to the contributing utilities.

(b) Corporate Manager

The Company is managed by the corporate manager, VELCO (the Manager). The Company and VELCO have common ownership and operate as a single functional unit. Under the Company's operating agreement, the Manager has complete discretion over the day-to-day business of the Company and provides all management services to the Company at cost. The Company itself has no employees and no governance structure separate from the Manager. The Company's operating agreement establishes that all expenses of the Manager related to managing the Company are paid for by the Company. These expenses consist primarily of all payroll and benefit related costs. All such costs are recorded in the Company's accounts as if they were direct expenses of the Company, and a corresponding due to Manager is recorded for the amount to be reimbursed to VELCO at a future date for such payroll and benefit related costs.

Additionally, the Company has included in the payable to VELCO, amounts related to taxes collected for deferred income taxes that have been recognized in rates and recorded as a deferred tax liability by VELCO prior to June 30, 2006; and for such liabilities that have arisen subsequent to June 30, 2006, pursuant to the Management Services Agreement for which a payment obligation was

assumed by the Company pursuant to the Transfer and Assumption Agreement. The deferred tax liability is due to temporary differences related to the deductibility of the excess of the tax over book depreciation. As these temporary differences reverse in future years, the Company will repay the obligation to the Manager. During December 2009, cash received from the sale of the Company's membership units was deposited to a VT Transco bank account which was subsequently swept to VELCO, resulting in a receivable from VELCO at December 31, 2009 of $39,287,043.

As of December 31, 2009 and 2008, the following amounts were due to/from VELCO and were included in the Company's balance sheet:

	2009	2008
Liability due to taxes collected	$ (11,425,140)	(9,464,588)
Liability due to payroll, pension and related benefit costs	(3,109,460)	(2,292,652)
Receivable due from VELCO	39,287,043	—
Due from (to) VELCO	$ 24,752,443	(11,757,240)

(c) Regulatory Accounting

The Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit specific incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when it is probable that such costs will be recovered in customer rates. Incurred costs are deferred as regulatory assets when the Company concludes that it is probable future revenues will be provided to permit recovery of the previously incurred cost. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence, and legal representations. A regulatory liability is recorded when amounts that have been recorded by the Company are likely to be refunded to customers through the rate-setting process.

On December 9, 2005, the FERC approved a filing allowing at that time VELCO, now the Company, to begin amortizing over a ten year period the deferred depreciation charges the Company incurred when taking depreciation under the bond sinking fund method. This regulatory asset which accounts for the difference between depreciation reported in the financial statements and depreciation previously recovered in rates is $2,552,332 and $2,977,721 as of December 31, 2009 and 2008, respectively.

On June 16, 2006, the FERC approved a filing allowing at the time VELCO, now the Company, to accumulate as a regulatory asset the costs associated with the Company's formation and to amortize and recover that asset over a fifteen year period to commence when the Company began operations. This regulatory asset is $1,678,553 and $1,824,514 as of December 31, 2009 and 2008, respectively.

As more fully described in note 7, the defined benefit pension and other postretirement regulatory assets of VELCO represent the unrecognized pension costs and postretirement costs that would normally be recorded as a component of other comprehensive income. Since these amounts represent costs that are expected to be recovered in future rates, they are recorded as regulatory assets in the

financial statements of the Manager. The regulatory asset related to these plans totaled $4,688,246 and $7,142,831 at December 31, 2009 and 2008, respectively, and is included in due from (to) VELCO in the accompanying financial statements.

The Company continually assesses whether regulatory assets continue to meet the criteria for probability of future recovery. This assessment includes consideration of factors such as changes in the regulatory environment, recent rate orders to other regulated entities under the same jurisdiction. If future recovery of certain regulatory assets becomes improbable, the affected assets would be written off in the period in which such determination is made.

(d) Revenue Recognition

Electric transmission service for utilities, municipalities, municipal electric companies, electric cooperatives, and other eligible entities is provided through the Company's facilities under the ISO-NE open-access transmission tariff regulated by FERC and the 1991 Vermont Transmission Agreement. The Company charges for these services under FERC approved rates. These tariffs specify the general terms and conditions of service on the transmission system and the approved rates set forth the revenue to be billed monthly based on actual cost of service plus an 11.5% return on capital for Class A Member units and a 13.3% return on capital for Class B Member units. The effect of unbilled revenue at the end of the accounting period represents the difference between billed and actual costs for the month of December and is $0 and $246,512 at December 31, 2009 and 2008, respectively, and has been reported in other assets in the accompanying financial statements.

(e) Utility Plant

Utility plant in service is stated at cost. Assets transferred to the Company from VELCO have been recorded at their original cost in utility plant with the related reserves for accumulated depreciation also recorded. (See note 2 for additional information.)

Major expenditures for plant and those which substantially increase useful lives are capitalized. The Company recognizes depreciation expense on gross plant at an average rate of 2.63% at December 31, 2009, 2008 and 2007 based on rates developed in a depreciation rate study. This method is consistent with the straight-line method of depreciation.

Software is recorded at cost. Amortization is recorded at straight-line rates over the estimated useful life of the assets which is five years.

(f) Long–Lived Assets

Long-lived assets, such as utility plant, and regulatory assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of assets may not be recoverable. If circumstances require a long-lived asset be tested for possible impairment, the Company first compares undiscounted cash flows expected to be generated by an asset to the carrying value of the asset. If the carrying value of the long-lived asset is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values and third-party independent appraisals, as

considered necessary. As long as its assets continue to be recovered through the ratemaking process, the Company believes that such impairment is unlikely.

(g) Allowance for Borrowed Funds Used during Construction

Allowance for funds used during construction (AFUDC) represents the cost of borrowed and equity funds used to finance the construction of transmission assets. The portion of AFUDC attributable to borrowed funds and the cost of equity funds is included as other income in the statements of income. AFUDC is not currently realized in cash, but is recovered in the form of increased revenue collected as a result of depreciation of the property. The Company capitalized AFUDC at an average rate of 5.75%, 7.35% and 7.10% in 2009, 2008 and 2007, respectively.

(h) Materials and Supplies Inventory

Materials and supplies are stated at the lower of cost or market. Cost is determined on a weighted average basis.

(i) Unamortized Debt Expense

Costs associated with the original issuance of long-term debt has been capitalized and amortized over the term of the debt using the effective interest rate method. Amortization expense amounted to $101,560, $97,788 and $95,261 in 2009, 2008 and 2007, respectively.

(j) Income Taxes

The Company is a limited liability company that has elected to be treated as a partnership under the Internal Revenue Code and applicable state statutes. As such, it is not liable for federal or state income taxes. The Company's members (except certain tax-exempt members) report their share of the Company's earnings, gains, losses, deductions and tax credits on their respective federal and state income tax returns. Accordingly, these financial statements do not include a provision for federal and state income tax expense. Income before tax reported on the statements of income is the Company's net income.

Beginning with the adoption of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* , included in FASB ASC Subtopic 740-10, *Income Taxes—Overall* , as of January 1, 2009, the Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs. The Company has concluded there are no material uncertain tax positions as of December 31, 2009. Prior to the adoption of Interpretation 48, the Company recognized the effect of income tax positions only if such positions were probable of being sustained.

The Company records interest related to unrecognized tax benefits in interest expense and penalties in administrative and general expenses.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

(k) Pension and Other Postretirement Plans

The Manager sponsors a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service and final average pay. The cost of this plan is recovered by the Company in rates and reimbursed to the Manager.

The Manager also sponsors a defined benefit healthcare plan for substantially all employees. The Manager measures the costs of its obligation based on its best estimate. The net periodic costs are recognized as employees render the services necessary to earn the postretirement benefits. The cost of this plan is recovered by the Company in rates and reimbursed to the Manager.

The Company adopted the measurement date provisions of FASB ASC 715-30, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* during fiscal year 2008 which required the Company to change its measurement date for plan assets and benefit obligations to December 31. The Manager adopted the measurement date provisions during fiscal year 2008, which required the Manager to change its measurement date for plan assets and benefit obligations to December 31. Prior to 2008, the Manager measured its plan assets and benefit obligations as of September 30. The total impact of the change in measurement date for both plans totaled $380,780 and was recovered in rates in 2009.

(l) Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant items subject to such estimates and assumptions include the carrying amount of utility plant, the recoverability of regulatory assets, assumptions used to estimate obligations related to employee benefits, and the assumptions used to estimate the fair value of financial instruments. The current economic environment has increased the degree of uncertainty inherent in those estimates and assumptions.

(m) Commitments and Contingencies

Liabilities for loss contingencies, arising from claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment can be reasonably estimated. Legal costs are expensed as incurred.

(n) Fair Value

On January 1, 2008, the Company adopted FASB Statement No. 157, *Fair Value Measurements* , included in ASC Topic 820, *Fair Value Measurements and Disclosures* , for fair value measurements of nonfinancial items that are recognized or disclosed at fair value in the financial statements on a recurring basis. Fair value is defined 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. ASC Topic 820 also establishes a framework for measuring fair value and expands disclosures about fair value measurements.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

On January 1, 2009, the Company adopted the provisions of ASC Topic 820 to fair value measurements of nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. There was no impact to the financial statements.

(2) Utility Plant

Utility plant consists of the following at December 31, 2009 and 2008:

	2009	2008
Land and rights of way	$ 58,577,888	32,813,905
Transmission equipment	484,504,675	428,726,805
Communications equipment	15,163,134	11,162,825
Buildings and office equipment	46,971,015	42,669,595
Construction work-in-process	122,001,001	52,553,116
	727,217,713	567,926,246
Less accumulated depreciation and amortization	97,522,547	89,288,784
	$ 629,695,166	478,637,462

Depreciation and amortization expense was $13,370,741, $10,168,747 and $7,691,370 as of December 31, 2009, 2008 and 2007, respectively.

(3) Members' Equity

The Company's members include municipalities, electric cooperatives, and investor-owned utilities. Class A Membership units are issued to taxable and tax exempt entities, and Class B Membership units are issued solely to tax exempt entities, such as the municipal utilities and electric cooperatives. At June 30, 2006, each member was issued membership interests in proportion to the value of transmission assets and/or cash it contributed to the Company for a total of $78,000,100 in Class A and Class B Membership units. During 2009, 2008 and 2007, each member was issued additional membership units in proportion to the value of cash it contributed to the Company for a total of $60,047,790, $38,683,000 and $113,750,000, respectively, in Class A and Class B Membership units. See note 12 for discussion of the $10,000,000 of mandatorily redeemable membership units issued to the Manager in 2008.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

Member's equity as of December 31, 2009, 2008 and 2007 is as stated in the table that follows.

	2009	2008	2007
Village of Barton	$ —	—	5,209
Village or Morrisville	1,311,868	1,311,867	1,290,448
Village of Orleans	—	—	5,340
Town of Readsboro	—	—	775
Swanton Village	612,110	612,110	612,110
Vermont Electric Cooperative	5,289,123	5,289,123	5,265,670
Washington Electric Cooperative	3,611,960	2,929,675	2,397,923
Central Vermont Public Service Corporation	114,763,263	87,698,447	78,840,936
Village of Stowe	21,071,663	19,451,068	750,568
Village of Northfield	306,503	306,503	306,503
Green Mountain Power Corporation	95,228,388	77,559,339	65,439,819
City of Burlington Electric Department	17,425,924	9,841,861	5,580,740
Village of Enosburg	—	—	7,675
Town of Hardwick	—	—	11,652
Village of Hyde Park	139,561	139,562	139,562
Village of Jacksonville	—	—	1,879
Village of Johnson	—	—	5,187
Village of Ludlow	—	—	16,513
Vermont Electric Power Company, Inc.	30,068,009	27,269,351	25,609,998
Village of Lyndonville	—	—	23,464
Vermont Public Power Supply Authority	35,641,061	17,269,475	11,889,820
	$ 325,469,433	249,678,381	198,201,791

Distribution of income before tax to members is at the discretion of the Manager. During 2009, 2008 and 2007, the Company distributed $26,879,761, $22,853,661 and $11,079,626, respectively, of its income before tax to its member in proportion to each member's percentage interest in the Company.

(4) Long-Term Debt

The Company has assumed all of the long-term debt associated with the assets that were transferred from VELCO. VELCO remains a co-obligor with the Company for First Mortgage Bond Series L, N, O, and P. Series Q, R and S were issued solely by the Company, with VELCO having no repayment obligation.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

(a) First Mortgage Bonds

The Company's First Mortgage Bonds outstanding include the following series at December 31, 2009 and 2008:

	2009	2008
Series L, 7.30% due through 2018	$ 7,412,000	8,021,000
Series N, 7.42%, due through 2012	20,813,000	21,823,000
Series O, 6.26% due through 2034	23,029,000	23,424,000
Series P, 5.72% due through 2036	30,000,000	30,000,000
Series Q, 5.59%, due through 2036	35,000,000	35,000,000
Series R, 5.75%, due through 2037	80,000,000	80,000,000
Series S, 4.81%, due through 2029	135,000,000	—
	331,254,000	198,268,000
Less bonds to be retired within one year	2,161,000	2,014,000
	$ 329,093,000	196,254,000

In October 2009, the Company received the proceeds from the sale of its Series S First Mortgage Bonds for the principal amount of $135,000,000, which the Company used to paydown its existing line of credit.

The First Mortgage Bonds are secured by a first mortgage lien on the Company's utility plant. The bonds to be retired through principal payments within the next five years and thereafter will amount to:

2010	$ 2,161,000
2011	11,821,000
2012	19,789,000
2013	11,821,000
2014	13,916,000
Thereafter	271,746,000
Total	$ 331,254,000

The terms of the indenture, as supplemented, under which the First Mortgage Bonds were issued, require, among other restrictions, that the total of Class A and B Members' investment and indebtedness of the Company subordinated to the First Mortgage Bonds must equal at least one-third of the aggregate principal amount of the bonds outstanding or $110,418,000 at December 31, 2009. The Company believes it is in compliance with this requirement at December 31, 2009.

(b) Other Debt

Other debt includes notes payable of $152,115 and $444,236 at December 31, 2009 and 2008, respectively, bearing interest at 5.44%, which matures June 1, 2010. The notes are secured by a lien on certain office equipment and furniture.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

(5) Notes Payable to Bank

The Company has an unsecured $120,000,000 line-of-credit agreement with a financial institution, reduced by certain standby letters of credit, expiring on December 27, 2010 to provide interim financing for utility plant construction. The Company's Manager is also an obligor on this facility. As part of this agreement, the Company agrees to pay 0.15% per annum on the daily unused line of credit amount. Average daily borrowing was $43,352,850 in 2009 at a weighted average interest rate of 2.42%. The outstanding balance at December 31, 2009 and 2008 amounted to $0 and $20,857,520, respectively.

(6) Income Taxes

Income tax liabilities are the responsibility of the Company's members (except certain tax-exempt members) and are not reflected in these financial statements. However, the Company is allowed to recover in rates, as a component of its cost of service, the amount of income taxes that are the responsibility of its members based on their ownership in the Company. Accordingly, the Company includes a provision for its members' federal and state current and deferred income tax expenses in its regulatory financial reports and rate filings. For purposes of determining the Company's revenue requirement under FERC-approved rates, rate base is reduced by an amount equivalent to net accumulated deferred taxes, including excess deferred tax reserves. Such amounts were approximately $34,400,000 in 2009 and $28,700,000 in 2008, and are primarily related to accelerated tax depreciation and other plant-related differences and are included in liability due to VELCO (note 1(b)).

(7) Pension and Other Postretirement Benefits

The Manager displays the net over-or-under funded position of a defined benefit pension and other postretirement plans as an asset or liability, with any unrecognized prior service costs, transition obligations or gains/losses reported as a component of other comprehensive income in stockholders' equity, unless the amount will be recoverable under the accounting guidance for regulated entities, in which case it would be recorded as a regulatory asset. As of December 31, 2009 and 2008, the Manager recorded a regulatory asset of $3,908,985 and $6,142,677, respectively, an unfunded defined pension obligation of $4,296,099 and $6,171,732, respectively, and a postretirement healthcare obligation of $922,732 and $821,048, respectively, and related regulatory asset of $779,261 and $1,000,154, respectively. Such amounts are reported in due to VELCO in the accompanying financial statements.

(a) Defined Benefit Plan

The Manager sponsors a defined benefit pension plan covering employees of the Company hired before January 1, 2008 who meet certain age and service requirements. The benefits are based on years of service and levels of compensation during the five years before retirement. The costs of the Manager's plan are an obligation of the Company as part of the Manager's fee.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

The following sets forth the Plan's benefit obligations, fair value of plan assets and funded status at December 31, 2009 and 2008:

	Pension benefits	
	2009	**2008**
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 17,053,020	13,985,144
Service costs	1,016,923	1,253,617
Interest cost	944,414	1,114,591
Actuarial loss (gain)	(1,108,509)	1,250,017
Benefits paid	(733,966)	(550,349)
Benefit obligation at end of year	17,171,882	17,053,020
Change in plan assets:		
Fair value of plan assets at beginning of year	10,881,288	12,654,874
Actual return on plan assets	1,822,461	(2,549,237)
Employer contribution	906,000	1,326,000
Benefits paid	(733,966)	(550,349)
Fair value of plan assets at end of year	12,875,783	10,881,288
Funded status	$ (4,296,099)	(6,171,732)
Accumulated benefit obligation	$ 12,575,266	12,082,659

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2009 and 2008, which recorded as a regulatory asset, are as follows:

	2009	**2008**
Effect of the change in measurement date to be recovered in rates	$ —	265,178
Net actuarial loss	3,527,325	5,443,363
	$ 3,527,325	5,708,541

The amount of the regulatory asset expected to be recognized as a component of net periodic pension cost in 2010 is $63,711.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

Net periodic benefit costs as of December 31, 2009, 2008 and 2007 are as follows:

	Pension benefits		
	2009	**2008**	**2007**
Components of net periodic benefit cost:			
Service cost	$ 1,016,923	1,253,617	758,614
Interest cost	944,414	1,114,591	817,913
Expected return on plan assets	(1,026,169)	(1,135,735)	(825,620)
Recognized net actuarial loss	11,235	27,818	81,154
Net amortization	52,476	65,596	52,476
Net periodic benefit cost	$ 998,879	1,325,887	884,537

The actuarial assumptions used to determine the pension benefit obligations are as follows:

	Pension benefits		
	2009	**2008**	**2007**
Weighted average assumptions:			
Discount rate, pension expense	6.00%	6.25%	5.75%
Discount rate, projected benefit obligation	6.00	6.00	6.25
Expected long-term rate of return on plan assets	7.50	7.50	7.50
Rate of compensation increase	4.50	4.50	4.50

Projected benefit payments to be paid in each year from 2010 to 2014 and the aggregate benefits to be paid in the five years from 2015 to 2019 are as follows:

	Pension benefit payments
Fiscal year ending December 31:	
2010	$ 659,640
2011	420,294
2012	526,804
2013	599,305
2014	787,360
2015 – 2019	4,394,909
Expected contribution for next fiscal year	$ 1,000,000

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

The following indicates the weighted average asset allocation percentage of the fair value of total plan assets for each major type of plan asset as of December 31, 2009 and 2008:

	Plan assets		Asset allocation	
Asset class	**2009**	**2008**	**2009**	**2008**
Money market	$ 1,346,097	1,344,066	10%	9%
Equities	7,704,246	6,060,580	60	68
Fixed income	3,825,440	3,476,642	30	23
Total	$ 12,875,783	10,881,288	100%	100%

The Manager's investment policy seeks to achieve sufficient growth to enable the plan to meet future benefit obligations to participants. The current asset allocation targets are 65% equity and 35% fixed income, reflecting the mid to long-term nature of the liabilities associated with the plan. The primary goals in the management of plan assets are to maintain the funds purchasing power and to maximize the mid to long-term total returns within a moderate risk environment by seeking both current income and the potential for long-term growth. The current fair value of pension plan assets is $12,875,783. Plan investments held at December 31, 2009 are classified as Level 1 based on the fair value hierarchy discussed in note 10.

(b) Postretirement Plan

The Manager's current postretirement benefit plan offers healthcare and life insurance benefits and these costs are an obligation of the Company under its contract with the Manager. The Manager accrues the cost of postretirement benefits during the employees' years of service. When the Manager began accrual accounting for such costs in 1993, it elected to recognize previously unaccrued postretirement benefit costs, known as the transition obligation, by amortizing these costs ratably over a 20-year period. For the years ended December 31, 2009, 2008 and 2007, the Manager contributed $32,141, $137,891 and $143,431, respectively, toward these benefits. The Company anticipates contributing $180,000 for these benefits in 2010.

The FERC has established certain guidelines that all FERC-regulated companies, including the Company, must follow in order to recover postretirement benefit costs in rates. The guidelines generally allow for the recovery of postretirement benefits when accrued. However, these guidelines do require that all postretirement benefit costs be funded when accrued. The Manager's current plan is to fund its annual postretirement benefits accrual by making deposits into a 401(h) account, a separate account established within the pension investment fund and through a Voluntary Employees' Benefit Association (VEBA). Additionally, these guidelines require the Manager to advise the FERC of its plans for accruing and funding postretirement benefit costs. The Manager filed its plans with the FERC in 1995, although such plans have not yet been approved by the FERC.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

The following sets forth the Plan's benefit obligations, fair value of plan assets and funded status at December 31, 2009 and 2008:

	Postretirement benefits	
	2009	**2008**
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 1,594,557	1,570,138
Service cost	93,871	95,852
Interest cost	82,303	113,129
Actuarial gain	(90,981)	(28,096)
Benefits paid	(183,618)	(156,466)
Benefit obligation at end of year	1,496,132	1,594,557
Change in plan assets:		
Fair value of plan assets at beginning of year	773,509	617,810
Actual return on plan assets	83,017	(125,623)
Employer contribution, net of reimbursement from VEBA	(99,508)	437,788
Benefits paid	(183,618)	(156,466)
Fair value of plan assets at end of year	573,400	773,509
Funded status	$ (922,732)	(821,048)

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2009 and 2008, which are recorded as a regulatory asset, are as follows:

	2009	**2008**
Change in measurement date to be recovered in rates	$ 61,145	115,602
Net actuarial loss	718,116	884,552
	$ 779,261	1,000,154

The amount of the regulatory asset expected to be recognized as a component of net periodic benefit cost in 2010 is $55,187.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for the healthcare plans. A 1.0% increase in the trend rate would increase the postretirement accumulated benefit obligation by $11,044 and a 1.0% decrease in the trend rate would decrease the postretirement accumulated benefit obligation by $10,366 in 2009.

VERMONT TRANSCO LLC

Notes to Financial Statements

December 31, 2009 and 2008

Net periodic benefit costs as of December 31, 2009, 2008 and 2007 are as follows:

	Postretirement benefits		
	2009	**2008**	**2007**
Components of net periodic benefit cost:			
Service cost	$ 93,871	95,852	67,397
Interest cost	82,303	113,129	88,743
Expected return on plan assets	(40,515)	(71,111)	(42,203)
Recognized net actuarial loss	22,234	27,793	40,041
Net amortization	32,953	37,360	22,234
Net periodic benefit cost	$ 190,846	203,023	176,212

The actuarial assumptions used to determine net periodic postretirement benefit costs are as follows:

	Postretirement benefits		
	2009	**2008**	**2007**
Weighted average assumptions:			
Discount rate, postretirement benefit	6.25%	6.25%	5.75%
Discount rate, projected benefit obligation	5.50	6.25	6.25
Expected return on plan assets	6.50	7.50	7.50
Rate of compensation increase	4.50	4.50	4.50

The following indicates the weighted average asset allocation percentage of the fair value of total plan assets for each major type of plan asset as of December 31, 2009 and 2008:

	Plan assets		Asset allocation	
Asset class	**2009**	**2008**	**2009**	**2008**
Cash and equivalents	$ 81,442	509,682	14%	66%
Equities	491,958	263,827	86	34
Total	$ 573,400	773,509	100%	100%

The Manager's investment policy seeks to achieve sufficient growth to enable the plan to meet future benefit obligations to participants. The current asset allocation targets are 87% equity, 12% fixed income and 1% cash, reflecting the mid to long-term nature of the liabilities associated with the plan. The primary goals in the management of plan assets are to maintain the funds purchasing power and

to maximize the mid to long-term total returns within a moderate risk environment by seeking both current income and the potential for long-term growth. The current fair value of postretirement plan assets is $573,400. Plan investments held at December 31, 2009 are classified as Level 1 based on the fair value hierarchy discussed in note 10.

(c) Supplemental Executive Retirement Plan

The Manager sponsors a nonqualified Supplemental Executive Retirement Plan to provide certain employees and former members of the Board of Directors of the Manager with additional retirement income. The Manager is funding the cost of the plan in part through life insurance contracts, the cash surrender value of which was $3,487,486 and $3,001,152 at December 31, 2009 and 2008, respectively. The cost of these plans, net of the increase in cash surrender value and insurance proceeds, if any, has been charged to operating expense in the accompanying statements of income. The actuarial assumptions used to determine net benefit costs under this plan are a discount rate of 5.00%, 6.00% and 5.75%, and a rate of compensation increase of 3.00% at December 31, 2009, 2008 and 2007. Aggregate benefits payable amounted to $4,673,191 and $4,393,503 at December 31, 2009 and 2008, respectively, and is recorded in due to VELCO.

(d) Deferred Compensation

The Manager has a deferred compensation plan for current and past officers and directors. Amounts deferred are at the option of the officer or director, and include annual interest on the amounts deferred. The total deferred compensation at December 31, 2009 and 2008 is $1,096,421 and $1,050,352, respectively, and is recorded in due to VELCO.

(e) Defined Contribution Plan

The Manager sponsors a defined contribution plan to which eligible employees may contribute part of their salaries and wages within prescribed limits. Employees are eligible to participate in this plan during their first year of employment, if the employee has attained age 18. Additional matching contributions may be made on the employees' behalf based on the results of operations. The Manager contributed $378,615, $354,666 and $307,560 in 2009, 2008 and 2007, respectively.

(8) Related Party Transactions

On December 31, 2008, the Manager borrowed $10,000,000 from the Company to purchase 1,000,000 mandatorily redeemable membership units in the Company. This is a demand note where the Manager may make payments, including accrued interest, at times it chooses until such time as the Company demands payment. Interest is at an Adjusted Libor Rate as calculated by KeyBank National Association.

Amounts included in due from related party at December 31, 2009 and 2008 are related to ongoing operating activities between the Company and VELCO.

The Manager and the Company have made available an unsecured, short-term credit facility to their related party, Vermont Electronic Transmission Company, Inc. (VETCO). The facility allows for borrowings of up to $2,000,000. The balance outstanding at December 31, 2009 and 2008 was $925,000 and $700,000, respectively.

CVPS personnel provide the Company with certain operational, maintenance, construction, and administrative services. In addition, payments were made by the Company to CVPS for material and supplies and insurance. These services are provided at cost and amounted to $465,075 and $697,174 in 2009 and 2008, respectively.

Similarly, GMP provides the Company with certain construction, maintenance, and operational services. These services are provided at cost or as the result of a competitive bidding process and amounted to $1,775,411 and $4,373,922 in 2009 and 2008, respectively.

(9) Asset Retirement Obligations

The Company continually reviews the regulations, laws, and contractual obligations to which it is party to identify situations where there are legal obligations to perform asset retirement activities. This review has identified a limited number of leases and railroad crossing agreements which obligate the Company to perform asset retirement activities upon termination. In considering how to determine the fair value of these obligations, the Company has determined that because of the limited number and limited size of the asset retirement obligations, the fair value of the obligations would not have a material impact on its financial position, results of operation and cash flows.

Deferred cost of removal represents estimated asset retirement costs that have previously been recovered from ratepayers for other than legal obligations. The Company expects, over time, to settle or recover through the rate-setting process any over or under collected net cost of removal. Cost of removal included in depreciation expense totaled $3,339,769 and $2,175,131 in 2009 and 2008, respectively.

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(10) Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2009 and 2008. Fair value is defined as the amount that would be received to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

	2009		2008	
	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:				
Cash	$ 733,150	733,150	72,900	72,900
Bond sinking fund deposits	526,000	526,000	490,000	490,000
Bond interest deposits	4,573,388	4,573,388	2,985,911	2,985,911
Accounts receivable	8,901,865	8,901,865	7,383,965	7,383,965
Notes receivable	10,925,000	10,925,000	10,700,000	10,700,000
Due from VELCO	39,287,043	39,287,043	—	—
Financial liabilities:				
Notes payable to bank	$ —	—	20,857,520	20,857,520
Accounts payable	10,343,646	10,343,646	7,862,009	7,862,009
Accrued interest on bonds	4,575,485	4,575,485	3,001,260	3,001,260
Long term debt	2,313,115	2,313,757	2,458,236	2,459,198
First mortgage bonds	329,093,000	325,414,901	196,254,000	200,555,031
Construction and other accrued expenses	13,878,348	13,878,348	13,557,140	13,557,140
Due to VELCO	14,534,600	14,534,600	11,757,240	11,757,240

The carrying amounts shown in the table are included in the balance sheets under the indicated captions. The fair values of the financial instruments shown in the above table as of December 31, 2009 and 2008 represent management's best estimates of the amounts that would be received to sell those assets or that would be paid to transfer those liabilities in an orderly transaction between market participants at that date. Those fair value measurements maximize the use of observable inputs. However, in situations where there is little, if any, market activity for the asset or liability at the measurement date, the fair value measurement reflects the Company's own judgments about the assumptions that market participants would use in pricing the asset or liability. Those judgments are developed by the Company based on the best information available in the circumstances.

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The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

- Cash, bond sinking fund deposits, bond interest deposits trade accounts receivable, notes payable to banks, accounts payable, accrued interest on bonds due from (to) VELCO, and construction and other accrued expenses: The carrying amounts, at face value or cost plus accrued interest, approximates fair value because of the short-term maturity of these instruments.
- Notes receivable: Because of the short-term maturity of this instrument, cost approximates fair value.
- Long-term debt and First mortgage bonds: The fair value of the Company's long-term debt is determined by discounting the future cash flows of each instrument at rates that reflect, among other things, market interest rates. At December 31, 2009 and 2008, the Company utilized Moody's long-term corporate bond yield average for utility entities with an Aa rating.

Fair Value Hierarchy

The Company adopted FASB ASC 820 on January 1, 2008 for fair value measurements of financial assets and financial liabilities and for fair value measurements of nonfinancial items that are recognized or disclosed at fair value in the financials on a recurring basis. On January 1, 2009, the Company adopted the provisions of ASC Topic 820 for fair value measurements of nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. This guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to measurements involving significant unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities as of the reporting date.

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 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.

There were no financial or nonfinancial assets or liabilities reported at fair value in the December 31, 2009 or 2008 financial statements.

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(11) Business and Credit Concentrations

(a) Significant Customers

One customer, ISO New England individually represents 74% and 80% of total accounts receivable at December 31, 2009 and 2008, respectively.

(b) Significant Capital Projects

The Company is in the process of performing construction projects to enhance services to its customers. Costs capitalized amounted to approximately $164,000,000 and $106,000,000 in 2009 and 2008, respectively, which related to projects estimated to be completed from 2009 – 2012, including: Lamoille County 115 kV Line, Southern Loop Project, Northwest Reliability Project, and East Avenue Loop. The Company has budgeted $119,000,000 for 2010 related to these projects which will be financed through bond issuance, capital contributions, and borrowings on the line of credit.

(12) Commitments

The Company reached a settlement with the Lamoille County municipal distribution utilities regarding cost allocations associated with the construction of a ten mile transmission line and associated substations that will benefit Lamoille County residents. Each member utility is allowed to purchase shares in the Company and use the arbitrage to assist in offsetting the "specific facility" costs. The specific facility charges are limited to an amount, stated in the settlement agreement, plus the difference between the member utilities interest payments on borrowed funds used to purchase Company membership units and the return on those units. After the ten year specific facility period as detailed in the settlement agreement, the membership units allocated are required to be resold to all Vermont distribution utilities with any remaining shares being re-purchased by the Company.

Additionally, VELCO, as manager is responsible to make up the difference between the specific facility payments of the individual utilities and the actual specific facility charges based on $35,000,000 of specific facility assets. To accomplish this, VELCO acquired 1,000,000 of the Company's membership units. As stated in the settlement agreement, these units are mandatorily redeemable in ten years when the shortfall has been fully covered. Under FASB ASC 480-10, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* , $10,000,000 has been recorded in the financial statements as a long-term liability for mandatorily redeemable 1,000,000 membership units.

(13) Subsequent Events

The Company has evaluated subsequent events from the balance sheet date through March 8, 2010, the date at which the financial statements were available to be issued, and determined there are no other items to disclose.