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

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

OR

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

Commission file number 001-08222

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

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files. Yes ☒ No ☐

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

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

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer (Do not check if a smaller reporting company)	☐	Smaller Reporting Company	☐

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

The aggregate market value of voting and non-voting common equity held by non affiliates of the registrant as of June 30, 2011 (2nd quarter) was approximately $321,686,306 (based on the $36.15 per share closing price of the Company's Common Stock, $6 Par Value, as reported on the New York Stock Exchange on June 30, 2011). In determining who are affiliates of the Company for purposes of computation, it is assumed that directors, officers, and other persons who held more than 5 percent of the issued and outstanding Common Stock of the Company on December 31, 2011, are "affiliates" of the Company. The characterization of such directors, officers, and other persons as affiliates is for the purposes of this computation only and should not be construed as a determination or admission for any other purpose.

On February 29, 2012 there were outstanding 13,479,392 shares of voting Common Stock, $6 Par Value.

DOCUMENTS INCORPORATED BY REFERENCE: None

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
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GLOSSARY OF TERMS

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

Current or former CVPS Companies, Segments or Investments

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

Regulatory and Other Authorities

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

Other

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

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

Cautionary Statements Regarding Forward-Looking Information Statements contained in this report that are not historical fact are forward-looking statements within the meaning of the 'safe-harbor' provisions of the Private Securities Litigation Reform Act of 1995. Whenever used in this report, the words "estimate," "expect," "believe," or similar expressions are intended to identify such forward-looking statements. Forward-looking statements involve estimates, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Actual results will depend upon, among other things:

- our ability to meet the requirements under the Merger Agreement with Gaz Métro;
- the actions of regulatory bodies with respect to our pending Merger with Gaz Métro, allowed rates of return, continued recovery of regulatory assets and alternative regulation;
- liquidity requirements;
- changes in the cost or availability of capital;
- our ability to replace or renegotiate our long-term power supply contracts;
- effects of and changes in local, national and worldwide economic conditions;
- effects of and changes in weather;
- volatility in wholesale power markets;
- our ability to maintain or improve our current credit ratings;
- the operations of ISO-NE;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- capital market conditions, including price risk due to marketable securities held as investments in trust for nuclear decommissioning, pension and postretirement medical plans;
- changes in the levels and timing of capital expenditures, including our discretionary future investments in Transco;
- the performance of other parties in joint projects, including other Vermont utilities, state entities and Transco;
- our ability to successfully manage a number of projects involving new and evolving technology;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- other presently unknown or unforeseen factors.

We cannot predict the outcome of any of these matters; accordingly, there can be no assurance as to actual results. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise. A more detailed assessment of the risks that could cause actual results to materially differ from current expectations is contained in Part I, Item 1A, Risk Factors.

PART I

Item 1. Business

Pending Merger with Gaz Métro On July 11, 2011, CVPS, Gaz Métro Limited Partnership ("Gaz Métro") and Danaus Vermont Corp., an indirect wholly owned subsidiary of Gaz Métro ("Merger Sub"), entered into an Agreement and Plan of Merger (the "Merger Agreement"). See Part II, Item 8, Note 1 – Business Organization, Pending Merger with Gaz Métro.

(a) General Description of Business Central Vermont Public Service Corporation ("we", "us", "our" or the "company") was incorporated in Vermont in 1929 and is the largest electric utility in Vermont. We engage principally in the purchase, production, transmission, distribution and sale of electricity. We serve approximately 160,000 customers in 163 towns, villages and cities in Vermont. Our Vermont utility operation is our core business. We typically generate most of our revenues through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-NE, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue from these sales helps to mitigate our power supply costs.

Our wholly owned subsidiaries include:

- C.V. Realty, Inc., a real estate company that owns, buys, sells and leases real and personal property and interests therein related to the utility business.
- East Barnet, formed to finance and construct a hydroelectric facility in Vermont, which became operational September 1, 1984. We have leased and operated it since the in-service date.

- CRC was formed to hold our investments in unregulated business opportunities. CRC's wholly owned subsidiary, SmartEnergy Water Heating Services, Inc., engages in the sale and rental of electric water heaters in Vermont and New Hampshire. On December 9, 2010, we dissolved CRC's wholly owned subsidiary, Eversant Corporation, the former parent of SmartEnergy Water Heating Services, Inc. There was no impact on our financial statements or results of operations.

Our equity ownership interests as of December 31, 2011 are summarized below:

- We own 58.85 percent of the common stock of VYNPC, which was initially formed by a group of New England utilities to build and operate a nuclear-powered generating plant in Vernon, Vermont. On July 31, 2002, the plant was sold to Entergy-Vermont Yankee. The sale agreement included a purchased power contract between VYNPC and Entergy-Vermont Yankee. Under the VY PPA, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates and, in turn, bills the purchased power contract charges from Entergy-Vermont Yankee with certain residual costs of service through a FERC tariff to us and the other Vermont Yankee sponsors. Our entitlement to energy produced by the Vermont Yankee plant is about 29 percent through March 21, 2012. Although we own a majority of the shares of VYNPC, our ability to exercise control is effectively restricted by the purchased power contract, the sponsor agreement among the group of New England utilities that formed VYNPC and the composition of the board of directors under which it operates.
- We own 47.10 percent of the common stock and 49.19 percent of the preferred stock of VELCO. In June 2006, VELCO transferred substantially all of its business operations and assets to Transco. VELCO's wholly owned subsidiary, VETCO, was formed to finance, construct and operate the Vermont portion of the 450 kV DC transmission line connecting the Province of Quebec with Vermont and the rest of New England.
- We own 36.59 percent of the voting equity units of Transco, which was formed by VELCO and its owners, including us, in June 2006. Transco owns and operates the high-voltage transmission system in Vermont. VELCO and its employees manage the operations of Transco under a Management Services Agreement. VELCO owns 9.23 percent of the voting equity units of Transco. Our total direct and indirect (through our VELCO ownership) interest in Transco is 40.93 percent of the voting equity units.
- We own 2 percent of the outstanding common stock of Maine Yankee and Connecticut Yankee and 3.5 percent of the outstanding common stock of Yankee Atomic. These plants have been decommissioned.

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

Vermont Marble Power Division: On June 10, 2011, the PSB issued an order approving our purchase of the Vermont Marble Power Division of Omya, Inc., pursuant to the purchase and sale agreement and issued a Certificate of Consent. On September 1, 2011, we closed on the transaction. Included in the sale are rights to serve approximately 875 customers, including the Omya industrial facility, which became our single-largest customer representing approximately 6 percent of expected future annual retail sales. The acquisition will create efficiencies that will reduce costs and benefit customers overall; and we acquired renewable hydro assets at competitive costs for our customers. See Part II, Item 8, Note 19 – Acquisitions.

(b) Financial Information about Industry Segments We have two principal operating segments, consisting of the principal regulated utility business and the aggregate of the other non-utility companies. See Part II, Item 8, Note 20 - Segment Reporting for financial information by segment.

(c) Narrative Description of Business As a regulated electric utility, we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. The ability to increase our customer base is limited to acquisitions or growth within our service territory. A number of factors affect our retail sales revenue including general economic conditions, weather and the opening, closing and changes in size of manufacturing and other business facilities. Retail sales volume over the last 10 years has remained essentially flat, with 2011 sales being higher than 2001 sales by 90.5 million kWh, or 4 percent. Annual changes between 2001 and 2011 ranged from a decrease of more than 1 percent in 2006 to increases of more than 2.3 percent in 2011. The 2011 increase is due to the acquisition of Vermont Marble in September 2011.

Our operating revenues consist primarily of retail and resale sales. Retail sales are comprised of sales to a diversified customer mix, including residential, commercial and industrial customers. Sales to the five largest retail customers receiving electric service accounted for about 6 percent of our annual retail electric revenues in 2011 and about 5 percent for both 2010 and 2009. On September 1, 2011, Omya industrial facility became our single-largest customer representing approximately 6 percent of expected future annual retail sales. Resale sales are comprised of long-term sales to third parties in New England, sales in the energy markets administered by ISO-NE and short-term system capacity sales. Operating revenues as of December 31 consisted of the following:

	Revenues			**Energy (MWh) Sales**		
	2011	2010	2009	**2011**	2010	2009
Retail Sales:						
Residential	**44%**	43%	41%	**33%**	33%	33%
Commercial	**33%**	32%	30%	**28%**	28%	27%
Industrial and other	**12%**	11%	10%	**16%**	13%	12%
Resale Sales	**7%**	11%	16%	**23%**	26%	28%
Other operating revenue	**4%**	3%	3%	**0%**	0%	0%

Retail Rates: Our retail rates are set by the PSB after considering the recommendations of Vermont's consumer advocate, the DPS. Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital. See Part II, Item 8, Note 9 - Retail Rates and Regulatory Accounting.

Wholesale Rates: We provide wholesale transmission service to eight network customers and six point-to-point customers under ISO-NE FERC Electric Tariff No. 3, Section II - Open Access Transmission Tariff (Schedules 21-CV and 20A-CV). We maintain an OASIS site for transmission on the ISO-NE web page.

Sources and Availability of Power Supply Our power supply portfolio includes sources used to serve our retail electric load requirements. Our current power and load forecasts suggest we have committed energy supplies in 2012 that are in balance with expected load. For the year ended December 31, 2011 energy generation and purchased power required to serve retail customers totaled 2,404,000 MWh. The maximum one-hour integrated demand during that period was 410.0 MW and occurred on December 29, 2011. For the year ended December 31, 2010 energy generation and purchased power required to serve retail customers totaled 2,359,000 MWh. The maximum one-hour integrated demand during that period was 406.1 MW and occurred on July 8, 2010. The sources of energy and capacity available to us for the year ended December 31, 2011 are as follows:

	Net Effective Capability	Generated and Purchased	
	12 Month Average MW	MWh	Percent
Wholly Owned Plants:			
Hydro	37.5	232,262	7.6
Diesel and Gas Turbine	20.3	470	0.0
Jointly Owned Plants:			
Millstone #3	21.4	161,681	5.2
Wyman #4	10.7	1,189	0.0
McNeil	10.4	45,488	1.5
Long-Term Purchases:			
VYNPC	177.8	1,420,705	46.1
Hydro-Quebec	143.2	922,901	30.0
Independent power producers	25.6	194,161	6.3
Other Purchases:			
System and other purchases	0.5	71,911	2.3
NEPOOL (ISO-New England)	46.2	30,407	1.0
Total	493.6	3,081,175	100.0

Wholly Owned Plants: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of 90.3MW. These plants include 24 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.05 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 63.8 MW and two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW.

Jointly Owned Plants: We have joint-ownership interests in three generating facilities and one transmission facility. As shown in the sources and availability of power supply table above, we receive our share of output and capacity from the three generating facilities. The Highgate Converter is directly connected to the Hydro-Québec system to the north and to the Transco system for delivery of power to Vermont utilities. This facility can deliver power in either direction, but predominantly delivers power from Hydro-Québec to Vermont. Additional information about these facilities is shown in the table below.

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

VYNPC: We purchase our entitlement share of Vermont Yankee plant output from VYNPC under a PPA between VYNPC and Entergy-Vermont Yankee, which expires on March 21, 2012. Prices per megawatt-hour under the contract will be $45 in 2012 and the contract contains a provision known as the "low market adjuster" that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. For additional information regarding VYNPC see Part II, Item 8, Note 4 - Investment in Affiliates and Note 18 - Commitments and Contingencies - Long-term Power Purchases.

Hydro-Québec: We purchase power from Hydro-Québec under the VJO power contract. The VJO is a group of Vermont electric companies, municipal utilities and cooperatives, of which we are a member. The VJO power contract has been in place since 1987 and purchases under the contract began in 1990. Related contracts were subsequently negotiated between us and Hydro-Québec that altered the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO power contract runs through 2020, but our purchases under the contract end in 2016. As of November 1, 2007 the annual load factor was reduced from 80 percent to 75 percent, and it will remain at 75 percent until the contract ends, unless the contract is changed or there is a reduction due to adverse hydraulic conditions. For additional information see Part II, Item 8, Note 18 - Commitments and Contingencies - Long-term Power Purchases.

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

The HQUS PPA will replace approximately 65 percent of the existing VJO power contract discussed above which, along with the VY PPA, supply the majority of Vermont's current power needs. The VJO power contract and the VY PPA expire within the next several years. See Part II, Item 8, Note 18 - Commitments and Contingencies - Long-term Power Purchases.

Independent Power Producers: We purchase power from several IPPs who own qualifying facilities under the Public Utilities Regulatory Policies Act of 1978. These facilities use water and biomass as fuel. Most of the power from qualifying facilities is allocated by a state-appointed purchasing agent that assigns power to all Vermont utilities under PSB rules. Starting in 2012, we will also purchase power directly from some larger independent producers, primarily wind projects, as a result of their successful participation in our 2009 competitive solicitation to wholesale market participants.

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

See Part II, Item 8, Note 18 - Commitments and Contingencies for additional information related to our long-term power contracts.

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

An amendment to Title 30 V.S.A. Section 212(a) enacted May 28, 1987 authorizes the DPS to purchase and distribute power at retail rates to all consumers of electricity in Vermont, subject to certain preconditions. Such sales have not been made in our service area since 1993.

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

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

Federal Power Act: Certain phases of our business and that of VELCO and Transco, including certain rates, are subject to regulation by the FERC. We are a licensee of hydroelectric developments under Part I of the Federal Power Act and, along with Transco, we are interstate public utilities under Parts II and III, as amended and supplemented by the National Energy Act.

In 2011 we received a license amendment for our Carver Falls hydroelectric facility to allow for the increase in installed capacity. We are in the process of relicensing three hydroelectric facilities that we acquired through the September 2011 purchase of Vermont Marble.

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

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

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

We cannot presently forecast the costs or other effects that environmental regulation may ultimately have on our existing and proposed facilities and operations. We believe that any such prudently incurred costs related to our utility operations would be recoverable through the ratemaking process. See Part II, Item 8, Note 18 - Commitments and Contingencies - Environmental.

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

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

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

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

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

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system and our production units. In 2011, capital expenditures were $41.1 million.

Capital expenditures for the years 2012 to 2014 are expected to range from $42 million to $69 million annually, including an estimated total of more than $25.5 million for CVPS SmartPower® over the three-year period. A portion of the CVPS SmartPower® project will be funded by the Smart Grid Stimulus Grant and this grant has reduced the estimated spending range above. Further discussion of the Smart Grid Stimulus Grant can be found below in Retail Rates and Alternative Regulation - CVPS SmartPower®.

Number of Employees At December 31, 2011, we had 515 employees. Of these employees, 206 were represented by Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers. On December 31, 2008, we agreed to a new five-year contract with our employees represented by the union, which expires on December 31, 2013.

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

Name and Age	**Office**	**Officer Since**
Lawrence J. Reilly, 56	President and chief executive officer	2011
Pamela J. Keefe, 46 (a)	Senior vice president, chief financial officer, and treasurer	2006
William J. Deehan, 59	Vice president - power planning and regulatory affairs	1991
Joan F. Gamble, 54	Vice president - strategic change and business services	1998
Brian P. Keefe, 54	Vice president - government and public affairs	2006
Joseph M. Kraus, 56	Senior vice president - operations, engineering and customer service	1987
Dale A. Rocheleau, 53	Senior vice president, general counsel and corporate secretary	2003

(a) Ms. Keefe will be resigning from the company effective March 30, 2012. On February 27, 2012 the Board of Directors appointed Edmund F. Ryan as the acting chief financial officer and treasurer for the company effective April 1, 2012. Mr. Ryan joined the Company in 2003. Prior to being appointed to his present position of acting chief financial officer and treasurer, he served as the Controller from November 2006 to March 2012, acting chief financial officer and treasurer from October 2005 to May 2006, and director of Internal Audit from August 2003 to October 2005. He previously served as Controller at The Home Service Store, Inc. from May 2000 to August 2003.

Mr. Reilly joined the Company March 2011. Prior to joining the company he served as an independent energy consultant from July 2008 to February 2011. From 1982 to July 2008, he was with National Grid USA and its predecessor, New England Electric System, in a variety of positions of increasing responsibility, including executive vice president and general counsel from 2001 to 2007, and executive vice president, legal and regulation from 2007 to 2008. Mr. Reilly also serves as president, CEO, and chair of our subsidiaries: East Barnet; C.V. Realty, Inc.; CRC; and SmartEnergy Water Heating Services, Inc. He serves as chair of the board of directors of our affiliate, VYNPC and is also a director of our affiliates: VELCO and VETCO. Mr. Reilly is a director of the Edison Electric Institute, Inc., the Vermont Technology Council, the Massachusetts Technology Park Corporation, and a member to the McGill Executive Institute advisory board.

Ms. Keefe joined the company in June 2006. Prior to being elected to her present position she served as vice president, chief financial officer, and treasurer from June 2006 to May 2009. Prior to joining the company, from 2003 to 2006 she served as senior director of financial strategy and assistant treasurer of IDX Systems Corporation ("IDX"); from 1999 to 2003 she served as director of financial planning and analysis and assistant treasurer at IDX. Ms. Keefe serves as a director, senior vice president, chief financial officer, and treasurer of our subsidiaries: East Barnet; C.V. Realty, Inc.; CRC; and SmartEnergy Water Heating Services, Inc. She also serves as a director of our affiliate, VYNPC. Additionally, Ms. Keefe serves as a member of the Rutland Regional Medical Center Investment Committee.

Mr. Deehan joined the company in 1985 with nine years of utility regulation and related research experience. Mr. Deehan was elected to his present position in May 2001. He serves as a director of the Joseph C. McNeil Generating Station, the Vermont Electric Power Producers, Inc., and the Rutland County Boys and Girls Club. Additionally, Mr. Deehan is a member of the International Association of Energy Economists and the Organizing Committee of the Rutgers University Advanced Regulatory Economics Workshop.

Ms. Gamble joined the company in 1989 with 10 years of electric utility and related consulting experience. Ms. Gamble was elected to her present position in August 2001. She serves as a director for our subsidiary SmartEnergy Water Heating Services, Inc. She is also on the board of and serves as secretary for the Rutland Regional Medical Center and Rutland Regional Health Service.

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

Mr. Kraus joined the company in 1981. Prior to being elected to his present position he served as senior vice president engineering and operations, general counsel, and secretary from May 2003 until November 2003. Mr. Kraus serves as a director of our subsidiaries: East Barnet; C.V. Realty, Inc.; CRC; and SmartEnergy Water Heating Services, Inc. Additionally, Mr. Kraus serves as a director of The Mentor Connector (a community-based, non-profit organization that matches volunteer mentors with children in need) and is a member of the Governor's Homeland Security Advisory Council.

Mr. Rocheleau joined the company in November 2003. Prior to being elected to his present position he served as senior vice president for legal and public affairs, and corporate secretary from November 2003 to September 2007. Prior to joining the company, he served as a director and attorney at law from 1992 to 2003 with Downs Rachlin Martin, PLLC. Mr. Rocheleau serves as a director, senior vice president, general counsel and corporate secretary of our subsidiaries: East Barnet; C.V. Realty, Inc.; CRC; and SmartEnergy Water Heating Services, Inc. He is also a member of the University of Vermont Board of Trustees. Additionally, he serves as a director of the Hartford Land Company and as director and president of the Rutland Economic Development Corporation.

Energy Conservation and Load Management The primary purpose of Conservation and Load Management programs is to offset the need for long-term power supply and delivery resources that are more expensive to purchase or develop than customer-efficiency programs, including unpriced external factors such as emissions and economic risk. The EEU, created by the state of Vermont to implement energy efficiency programs throughout Vermont, began operation in January 2000. We have a continuing obligation to provide customer information and referrals, and coordination of customer service, power quality, and any other distribution utility functions, which may intersect with the EEU's activities. After a thorough investigation, the PSB revisited the structure and scope of the EEU to facilitate its participation in the FCM, lengthen its planning horizon and expand its scope to include non-electric efficiency. As part of the process, the PSB transformed the EEU structure from one based on delivery of services under contract with the PSB to a more flexible approach based on an order of appointment.

By order issued on December 20, 2010, the Vermont Energy Investment Corporation was issued an Order of Appointment to serve as the EEU within the company's service area. The Order of Appointment defines the responsibilities of the EEU and the process for administering the order. The EEU's activities include the delivery of energy efficiency services to all customers and for the delivery of services targeted to areas as prescribed in the Demand Response Plan developed by the PSB to guide the activities of the EEU.

We have retained the obligation to provide certain demand side management programs, including responsibilities involving the design and implementation of demand response programs, rate designs, and as a part of Distributed Utility Planning to solve supply problems and reliability deficiencies. DUP is designed to ensure that safe, reliable delivery services are provided at least cost.

We also participate in the Vermont System Planning Committee ("VSPC") established by the PSB as part of the process for development of the state's Long-Term Transmission Plan. The VSPC consists of representatives of the DPS, the distributed utilities, VELCO and other stakeholders. Issues associated with the selection of areas for the receipt of geotargeted EEU services have been vetted through the VSPC process prior to their adoption by the PSB. Areas within the CVPS service area have received such treatment and are expected to continue to be subject to targeted efficiency programs by the EEU.

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

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

(e) Available Information We make available free of charge through our Internet Web site, *www.cvps.com,* our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after electronically filing with the SEC. Access to the reports is available from the main page of the Internet Web site through "Investor Relations." Our Corporate Ethics and Conflict of Interest Policy, Corporate Governance Guidelines, and Charters of the Audit, Compensation and Corporate Governance Committees are also available on the Internet Web site. Access to these documents is available from the main page of our Internet Web site under "About us" and then "Corporate Governance." Printed copies of these documents are also available upon written request to the Assistant Corporate Secretary at our principal executive offices. Our reports, proxy, information statements and other information are also available by accessing the SEC's Internet Web site, *www.sec.gov*, or at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. Information regarding operation of the Public Reference Room is available by calling the SEC at 1-800-732-0330.

Item 1A. Risk Factors

Risks Relating to Our Business We operate in a market and regulatory environment that involves significant risks, many of which are beyond our control, cannot be limited cost-effectively or may occur despite our risk-mitigation strategies. Each of the following risks could have a material effect on our performance. Also see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Other Business Risks and Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

We have risks related to the proposed merger with Gaz Métro .

We may be unable to satisfy the conditions or obtain the approvals required to complete the merger or such approvals may contain material restrictions or conditions. On September 29, 2011, CVPS held a Special Meeting of Shareholders. At the meeting, the shareholders approved the Agreement and Plan of Merger, effective as of July 11, 2011, and in a non-binding advisory vote approved the change-in-control payments related to the Merger. The Merger is subject to other conditions, including the approval of various government agencies. Governmental agencies may not approve the Merger or may impose terms and conditions that could result in a delay or termination of the Merger or increase the costs of the Merger. See Part II, Note 1 – Business Organization, Pending Merger with Gaz Métro.

The merger may not be completed, which may have an adverse effect on our share price and future business and financial results. Failure to complete the merger or an unanticipated delay in doing so could negatively affect our share price, as well as our future business and financial results. Proposed class actions have been brought against our board of directors on behalf of CVPS common shareholders. See Part II, Note 1 – Business Organization, Litigation Related to Merger Agreement, for discussion of pending litigation related to the merger.

We are subject to business uncertainties and contractual restrictions while the merger is pending. The work required to complete the merger may place a burden on management and internal resources as their attention may be focused on the merger instead of day-to-day management activities, including pursuing other opportunities. While the merger is pending, our business operations are restricted by the Merger Agreement to ordinary course of business activities without the approval of Gaz Métro , which may cause us to forgo otherwise beneficial opportunities.

We may lose management personnel and other key employees and be unable to attract and retain such personnel and employees. Uncertainties about the effect of the merger on management personnel and employees may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, which could affect our financial performance.

We are subject to substantial utility-related regulation on the federal, state and local levels, and changes in regulatory or legislative policy could jeopardize our full recovery of costs. At the federal level, the FERC regulates our transmission rates, affiliate transactions, the acquisition by us of securities of regulated entities and certain other aspects of our business. The PSB regulates the rates, terms and conditions of service, various business practices and transactions, financings, transactions between us and our affiliates, and the siting of our transmission and generation facilities and our ability to make repairs to such facilities. Our allowed rates of return, rate structures, operation and construction of facilities, rates of depreciation and amortization, and recovery of costs (including decommissioning costs and exogenous costs such as storm response-related expenses) are all determined within the regulatory process. The timing and adequacy of regulatory relief directly affect our results of operations and cash flows. Under state law, we are entitled to charge rates that are sufficient to allow us an opportunity to recover reasonable operation and capital costs and a return on investment to attract needed capital and maintain our financial integrity, while also protecting relevant public interests. We prepare and submit annual filings with the DPS for review and with the PSB for review and approval. The PSB may deny the recovery of costs incurred for the operation, maintenance, and construction of our regulated assets, as well as reduce our return on investment. Furthermore, compliance with regulatory and legislative requirements could result in substantial costs in our operations that may not be recovered. Also see Part II, Item 8, Note 9 - Retail Rates and Regulatory Accounting, for additional information.

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

Unexpected ice, wind and snow storms or extraordinarily severe weather can dramatically increase costs, with a significant lapse of time before we recover these costs through our rates. The demand for our services and our ability to provide them without material unplanned expenses are directly affected by weather conditions. Weather conditions also directly influence the demand for electricity. We serve a largely rural, rugged service territory with dense forestation that is subject to extreme weather conditions. Storm activity has been significant in recent years. Our results of operations can be affected by changes in weather. Severe weather conditions such as ice and snow storms, high winds and natural disasters may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period. We typically receive the five-year average of storm restoration costs in our rates. Costs from major storms that exceed this amount may qualify as an exogenous factor and subsequently be recovered, as defined in our Alternative Regulation Plan. We incurred $9.2 million of storm response-related costs from Tropical Storm Irene 2011 and $8.4 million of these costs qualify as an exogenous factor. We recovered similar major storm response-related costs in 2010 and 2009. Also, see Part II, Item 7, Retail Rates and Regulatory Accounting.

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

Any failure by us to comply with environmental laws and regulations, even if due to factors beyond our control or reinterpretations of existing requirements, could also increase costs. Existing environmental laws and regulations may be revised or new laws and regulations seeking to protect the environment may be adopted or become applicable to us. The cost impact of any such legislation would be dependent upon the specific requirements adopted and cannot be determined at this time. We believe that we are materially in compliance with all applicable environmental and safety laws and regulations; however, there can be no assurance that we will not incur significant costs or liabilities in the future.

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

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

Longer-term disruptions in the capital markets as a result of economic uncertainty, changes in regulation, reduced financing alternatives or failures of financial institutions could adversely affect our access to the funds needed to operate our business. Such prolonged disruptions could require us to take measures to conserve cash until the markets stabilize. In addition, if our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed, and future results of operations could be adversely affected.

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

We routinely review options to issue debt and equity to support working capital requirements resulting from investments in our distribution and transmission system and investments in Transco.

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

We have risks related to our power supply and wholesale power market prices and we could be exposed to high wholesale power prices that could be material. The majority of our future MWh purchases are through contracts with Hydro-Québec. If this source becomes unavailable for a period of time, we could be exposed to higher wholesale power prices and that amount could be material, although current spot and forward market prices imply this would not be the case. Additionally, this could significantly impact our liquidity due to the potentially high cost of replacement power and performance assurance collateral requirements arising from purchases through ISO-NE or third parties. Most incremental replacement power costs would be recovered through the power cost adjustment mechanism in our alternative regulation plan or we could seek emergency rate relief from our regulators if this were to occur. Such relief may or may not be provided and if it is provided we cannot predict its timing or adequacy.

Deliveries under the current contract with Hydro-Québec end in 2016, but the level of deliveries will begin to decrease after 2012. There is a risk that other sources available to fill out our portfolio may not be as reliable, and the price of such replacement power could be significantly higher than what we have in place today although current spot and forward market prices imply this would not be the case. In August 2010, we signed a new contract for ongoing Hydro-Québec supplies. The contract was approved by the PSB on April 15, 2011.

For additional information on our material power supply contracts, see Part II, Item 8, Note 18 – Commitments and Contingencies – Long-term Power Purchases.

An economic downturn and customers' conservation efforts could reduce energy consumption and adversely affect our results of operations, cash flows or financial position. Our business follows the economic cycles of the customers we serve. The economic downturn, subsequent recession and increased cost of energy supply have and could continue to adversely affect energy consumption and therefore impact our results of operations. Economic downturns, prolonged recoveries or periods of high energy supply costs typically lead to reductions in energy consumption and increased conservation measures. These conditions could adversely impact the level of energy sales and result in less demand for energy delivery. Anticipated consumer demand is reflected in base rates set annually under the plan; if demand was more or less during the year than the level reflected in rates, the difference could negatively impact our operations. The effect of significant unanticipated increases or decreases in consumer demand on our revenue will be offset in part by the power cost and earnings sharing adjustment mechanism in the alternative regulation plan. Also see Part II, Item 8, Note 9 - Retail Rates and Regulatory Accounting, for additional information.

Extreme weather conditions, breakdowns, war, acts of terrorism or other occurrences could lead to the loss of use or destruction of our facilities or the facilities of third parties that are used in providing our services, or with which our electric facilities are interconnected, and could greatly reduce cash flows and increase our costs of repairs and/or replacement of assets. Our ability to provide energy delivery and related services depends on our operations and facilities and those of third parties, including ISO-NE and electric generators from which we purchase electricity. While we carry property insurance to protect certain assets and general regulatory precedent may provide for the recovery of losses for such incidents, our losses may not be fully recoverable through insurance or customer rates. On August 28, 2011, Tropical Storm Irene severely impacted the northeast, including our service territory, resulting in approximately 73,000 CVPS customer outages. In preparation for the storm, we secured outside utility and tree crews from as far away as Illinois, Missouri and Texas, and we restored power to our last customer on September 2, 2011. We incurred $9.2 million of storm response-related costs from the storm and $8.4 million of these costs qualify as an exogenous factor.

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

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

Adoption of new accounting pronouncements and application of accounting guidance for regulated operations can impact our financial statements. The adoption of new accounting standards and changes to current accounting policies or interpretations of such standards may materially affect our financial position, results of operations or cash flows. Accounting policies also include industry-specific accounting standards applicable to rate-regulated utilities. If we determine that we no longer meet the criteria to account for regulated operations, the accounting impact would be a charge to operations of $18.1 million on a pre-tax basis as of December 31, 2011, assuming no stranded cost recovery would be allowed through a rate mechanism. We would also be required to record pension and postretirement costs of $26.4 million on a pre-tax basis to Accumulated Other Comprehensive Loss and $0.3 million to Retained Earnings as a reduction in stockholders' equity and would be required to determine any potential impairment to the carrying costs of deregulated plant. The financial statement impact resulting from the discontinuance of accounting for regulated operations might also trigger certain defaults under our current financial covenants.

The effect of the adverse impacts from these risk factors on our utility earnings could be mitigated by the earnings sharing adjustment mechanism in the alternative regulation plan effective through December 31, 2013.

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

We have other business risks related to liquidity. If our Hydro-Quebec purchased power source became unavailable or similar events occurred, they could have a significant effect on our liquidity due to the potentially high cost of replacement power and performance assurance requirements arising from purchases through ISO-NE or third parties although current spot and forward market prices imply this would not be the case.

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

In 2011, we renewed our three-year $40 million unsecured revolving credit facility and also have a three-year $15 million unsecured revolving credit facility with a different lending institution. We also issued $40 million of first mortgage bonds, Series WW, due in 2041; of which $20 million was used to redeem the Series SS Bonds. The remaining proceeds are being used for our capital expenditures and for other corporate purposes. These WW bonds were issued under a shelf facility that allows us to issue up to an additional $60 million of first mortgage bonds directly to the purchaser through December 31, 2012. Neither party has any obligation to issue or purchase the additional $60 million first mortgage bonds.

Our credit facilities provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements in the form of funds borrowed and letters of credit. If we are ever unable to secure needed funding, we would review our corporate goals in response to the financial limitation. Other material risks to cash flow from operations include: loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; significant or prolonged storm-related outages; increases in net power costs due to lower-than-anticipated margins on sales revenue from excess power or an unexpected power source interruption; required prepayments for power purchases; and increases in performance assurance requirements described above, as a result of high power market prices.

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

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

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

An inability to access capital markets at attractive rates could materially increase our expenses. We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Our business is capital intensive and dependent on our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs could increase materially, our financial condition could be harmed and future results of operations could be adversely affected.

Our current credit rating is subject to change and ratings below investment grade could increase our capital costs and collateral requirements. In December 2011, Moody's Investors Service affirmed our issuer rating of Baa3, which is investment grade. Maintaining an investment-grade rating benefits our customers and shareholders by giving us access to lower-cost capital, more power purchase and sale counterparties, and higher collateral thresholds. Looking ahead, as long-term power contracts with Hydro-Québec and Vermont Yankee begin to expire, these ratings become even more important due to the role they play in pricing and collateral requirements.

The costs associated with healthcare or pension obligations could escalate at rates higher than anticipated, which could adversely affect our results of operations and cash flows. Active employee and retiree healthcare and pension costs are a significant part of our cost structure. The costs associated with healthcare or pension obligations could escalate at rates higher than anticipated, which could adversely affect our results of operations and cash flows, if costs exceeded amounts allowed to be recovered in our rates. A portion of potential unanticipated higher costs could be recovered under the ESAM adjustment, included in our alternative regulation plan. Also, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, Pension and Postretirement Medical Benefits.

We have risks related to cyber security that could interfere with our operations and result in theft of personally identifiable information. Existing and new technologies that we are beginning to deploy represent a path that potential attackers may attempt to exploit. Due to the inter-connected nature of our distribution, transmission and generation systems, a cyber attack could disrupt operations. Such a disruption to operations could hinder our provision of reliable electricity services to customers. Cyber security risks could also include other financial and business systems and could compromise security of confidential personal information, ranging from personally identifiable information stored in applications to employee-related information. A security breach could diminish regulatory and customer support for the CVPS SmartPower® program.

We have risks related to the cost and implementation of new technology projects. The CVPS SmartPower® project involves the deployment of technologies that will change our business in fundamental ways. We believe these changes will be in the best interest of the company and our customers. However, there is the possibility that exogenous factors could negatively impact the anticipated benefits of these changes and we cannot say with certainty that the deployment of these technologies will not present some risks to the company and its operations.

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

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

We have risks associated with the operation of nuclear facilities. Changes in security and safety requirements could result from events such as a serious nuclear incident outside of our control. The NRC plans to perform additional operational and safety reviews of nuclear facilities in the U.S. due to the nuclear-related incidents in Japan resulting from the March 2011 earthquake and tsunami. The lessons learned from the Japan events and NRC reviews may impact future operations and capital requirements at U.S. nuclear facilities. Although we have no reason to anticipate a serious nuclear incident at the nuclear plants in which we have an ownership interest, if an incident did occur, it could have a material adverse effect on our financial position, results of operations and cash flows.

We have risks associated with the negative effects of the U.S. debt downgrade, which initially had an adverse effect on financial markets. On August 5, 2011, Standard & Poor's lowered the long-term sovereign credit rating of U.S. Government debt obligations from AAA to AA+. On August 8, 2011, S & P also downgraded the long-term credit ratings of U. S. government sponsored enterprises. We are unable to predict the long-term impact on such markets and the impact on the fair value of our investments in pension and postretirement medical trust funds, our Millstone Unit #3 decommissioning trust fund and our Rabbi Trust variable life insurance policies.

We have risks associated with our transmission costs and we could be exposed to higher transmission costs from our affiliate, Transco that could be material. Under the VTA, Transco's costs are offset by credits under the NOATT for certain high voltage transmission facilities they own and for certain services they provide. Transco is also reimbursed for the costs of certain facilities they own that benefit specific Vermont utilities. Net Transco costs are billed to Vermont utilities under the VTA. A decrease in Transco's regional network service revenues could increase costs for Vermont utilities. We recover the majority of our share of any higher costs under the PCAM adjustment, included in our alternative regulation plan.

While regional cost-sharing greatly reduces our costs related to qualifying Vermont transmission facilities, we pay our share of the costs of all new and existing NOATT-qualifying facilities located throughout New England.

Item 1B. Unresolved Staff Comments None

Item 2. Properties We own all of our principal plants and important units, including those of our consolidated subsidiaries. Transmission and distribution facilities that are not located in or over public highways are, with minor exceptions, located on land owned in fee or pursuant to easements, most of which are perpetual. Transmission and distribution lines located in or over public highways are located pursuant to authority conferred on public utilities by statute, subject to regulation of state or municipal authorities. Substantially all of our utility property and plant is subject to liens under our First Mortgage Indenture.

Our properties are operated as a single system that is interconnected by the transmission lines of Transco, New England Power and PSNH. We own and operate 26 small generating stations in Vermont with a total current nameplate capability of 90.3 MW. Our joint ownership interests include: a 1.7769 percent interest in an oil-generating plant in Maine; a 20 percent interest in a wood-, gas- and oil-fired generating plant in Vermont; a 1.7303 percent interest in a nuclear generating plant in Connecticut; and a 47.52 percent interest in a transmission interconnection facility in Vermont. Additional information with respect to these properties is set forth under Part I, Item 1, Business, Sources and Availability of Power Supply and is incorporated herein by reference.

At December 31, 2011, our electric transmission and distribution systems consisted of approximately 621 miles of overhead transmission lines, 8,532 miles of overhead distribution lines and 485 miles of underground distribution lines. All are located in Vermont except for approximately 23 miles in New Hampshire and 2 miles in New York.

Transco's properties consist of approximately 672 miles of high-voltage overhead and underground transmission lines and associated substations. The lines connect on the west with the lines of National Grid New York at the Vermont-New York border near Whitehall, New York and Bennington, Vermont, and with the submarine cable of New York Power Authority near Plattsburgh, New York; on the south and east with the lines of National Grid New England, Public Service Company of New Hampshire and Northeast Utilities; on the south with the facilities of Vermont Yankee and with National Grid New England near Adams, Mass.; and on the northern border of Vermont with the lines of Hydro-Québec near Derby, Vermont and through the Highgate converter station and tie line that we jointly own with several other Vermont utilities.

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

Item 3. Legal Proceedings
We are involved in legal and administrative proceedings in the normal course of business, including civil litigation. We are unable to fully determine a range of reasonably possible court-ordered damages, settlement amounts, and related litigation costs or legal liabilities that would be in excess of amounts accrued and amounts covered by insurance. Based on the information currently available, we do not believe that it is probable that any such legal liability will have a material impact on our consolidated financial position. However, it is reasonably possible that additional legal liabilities that may result from changes in estimates could have a material impact on our results of operations, financial condition or cash flows. See Part II, Note 1 – Business Organization, Litigation Related to Merger Agreement, for discussion of pending litigation related to the merger.

Item 4. Mine Safety Disclosures None

PART II

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

(a) Our common stock is listed on the NYSE under the trading symbol CV.

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

	Market Price	
2011	High	Low
First Quarter	**$23.76**	**$21.01**
Second Quarter	**$36.36**	**$22.14**
Third Quarter	**$36.35**	**$34.31**
Fourth Quarter	**$35.60**	**$35.01**
2010	High	Low
First Quarter	$21.48	$18.72
Second Quarter	$22.83	$19.00
Third Quarter	$22.14	$19.09
Fourth Quarter	$22.70	$19.75

(b) As of February 29, 2012, there were 5,211 holders of our Common Stock, $6 par value.

(c) Common Stock dividends have been declared quarterly and cash dividends of $0.23 per share were paid for all quarters of 2011 and 2010.

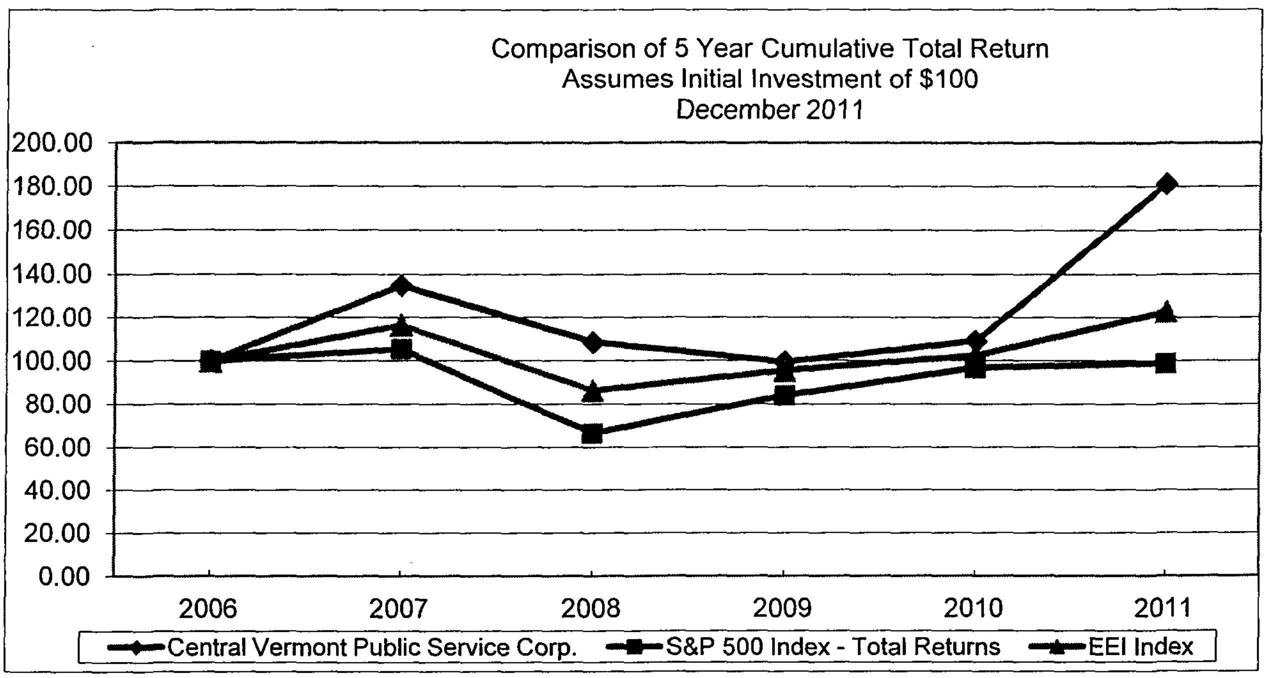
So long as any Senior Preferred Stock is outstanding, except as otherwise authorized by vote of two-thirds of such class, if the Common Stock Equity (as defined) is, or by the declaration of any dividend will be, less than 20 percent of Total Capitalization (as defined), dividends on Common Stock (including all distributions thereon and acquisitions thereof), other than dividends payable in Common Stock, during the year ending on the date of such dividend declaration, shall be limited to 50 percent of the Net Income Available for Dividends on Common Stock (as defined) for that year; and if the Common Stock Equity is, or by the declaration of any dividend will be, from 20 percent to 25 percent of Total Capitalization, such dividends on Common Stock during the year ending on the date of such dividend declaration shall be limited to 75 percent of the Net Income Available for Dividends on Common Stock for that year. The defined terms identified above are used herein in the sense as defined in subdivision 8A of our Articles of Association; such definitions are based upon our unconsolidated financial statements. As of December 31, 2011, the Common Stock Equity of our unconsolidated company was 52.1 percent of Total Capitalization.

Our First Mortgage Bond indenture contains certain restrictions on the payment of cash dividends on capital stock and other Restricted Payments (as defined). This covenant limits the payment of cash dividends and other Restricted Payments to our Net Income (as defined) for the period commencing on January 1, 2001 up to and including the month next preceding the month in which such Restricted Payment is to be declared or made, plus approximately $77.6 million. The defined terms identified above are used herein in the sense as defined in Section 5.09 of the Forty-Fourth Supplemental Indenture dated June 15, 2004; such definitions are based upon our unconsolidated financial statements. As of December 31, 2011, $79.9 million was available for such dividends and other Restricted Payments.

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

(e) The performance graph showing our five-year total shareholder return follows:

The SEC requires that we include in our Annual Report on Form 10-K a line-graph presentation comparing cumulative, five-year stockholder returns on an indexed basis with the S&P 500 Stock Index and either a published industry or line-of-business index or an index of peer companies selected by us. The company has selected for its peer group index a stock index compiled by EEI, because it is the most comprehensive and representative index that includes stock performance data for U.S. investor-owned electric utility companies. During the five year period shown (2006-2011), we outperformed both the EEI Index and the S&P 500 Stock Index.



	2006	2007	2008	2009	2010	2011
CVPS	100.00	134.97	108.64	99.39	109.17	181.28
S&P 500	100.00	105.50	66.47	84.05	96.72	98.77
EEI Index	100.00	116.56	86.37	95.62	102.35	122.81

Item 6. Selected Financial Data

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

(in thousands, except per share amounts)	**2011**	2010	2009	2008	2007
Income Statement					
Operating revenues	**$359,734**	$341,925	$342,098	$342,162	$329,107
Net income (a)	**$5,704**	$20,954	$20,749	$16,385	$15,804
Per Common Share Data					
Basic earnings per share	**$0.40**	$1.66	$1.75	$1.53	$1.52
Diluted earnings per share	**$0.40**	$1.66	$1.74	$1.52	$1.49
Cash dividends declared per share of common stock	**$0.92**	$0.92	$0.92	$0.92	$0.92
Balance Sheet					
Long-term debt (b)	**$240,578**	$188,300	$201,611	$167,500	$112,950
Capital lease obligations (b)	**$2,471**	$3,471	$4,313	$5,173	$5,889
Redeemable preferred stock	**$0**	$0	$0	$1,000	$2,000
Total capitalization (b)	**$519,257**	$472,553	$445,401	$401,206	$317,700
Total assets	**$776,265**	$710,746	$632,152	$626,126	$540,314

(a) In 2011, merger expenses, net of related tax benefit, reduced net income by $16 million, or $1.19 per share.
(b) Amounts exclude current portions.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
In this section we discuss our general financial condition and results of operations. Certain factors that may impact future operations are also discussed. Our discussion and analysis are based on, and should be read in conjunction with, the accompanying Consolidated Financial Statements. The discussion also includes non-U.S. GAAP measures referencing earnings per diluted share for variances described below in Results of Operations. We use this measure to provide additional information and believe that this measurement is useful to investors to evaluate the actual performance and contribution of our business activities. This non-U.S. GAAP measure should not be considered as an alternative to our consolidated fully diluted EPS determined in accordance with U.S. GAAP as an indicator of our operating performance.

COMPANY OVERVIEW
We are regulated by the PSB, the FERC and the Connecticut Department of Public Utility Control with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital. As discussed under the heading Retail Rates and Alternative Regulation below, the PSB approved, with modifications, the alternative regulation plan that we proposed in August 2007. The implementation of this plan on January 1, 2009, has provided timelier rate adjustments to reflect changes in power, operating and maintenance costs, which better serve the interests of customers and shareholders. By order dated March 3, 2011, the PSB approved further amendments to the alternative regulation plan that: 1) extend its duration until December 31, 2013; 2) alter the methodology for implementing the non-power-cost cap contained in the plan; 3) reset our allowed ROE; and 4) remove provisions no longer applicable to the provision of our services. These amendments are consistent with the terms of an ARP MOU that was filed with the PSB on December 21, 2010, except that the PSB approved an ROE for us for 2011 of 9.45 percent, rather than the 9.59 percent contained in the ARP MOU.

As a regulated electric utility, we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. The ability to increase our customer base is limited to acquisitions or growth within our service territory. A number of factors affect our retail sales revenue, including general economic conditions, weather and the opening, closing and changes in size of manufacturing and other business facilities. Retail sales volume over the last 10 years has remained essentially flat, with 2011 sales being higher than 2001 sales by 90.5 million kWh, or 4 percent. Annual changes between 2001 and 2011 ranged from a decrease of more than 1 percent in 2006 to increases of more than 2.3 percent in 2011. The 2011 increase is due to the acquisition of Vermont Marble in September 2011.We currently have sufficient power resources in balance with our forecasted load requirements.

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

EXECUTIVE SUMMARY
The results of our operations for 2011 were earnings of $5.7 million, or $0.40 per diluted share of common stock. Excluding merger-related expenses of $16 million after-tax, or $1.19 per diluted share of common stock, the results of our operations for 2011 were earnings of $21.7 million, or $1.59 per diluted share of common stock. This compares to 2010 earnings of $21 million, or $1.66 per diluted share of common stock and 2009 earnings of $20.7 million, or $1.74 per diluted share of common stock.

	2011	
	Net Income (in millions)	**Earnings Per Diluted Share**
Net earnings excluding merger-related expenses	$21.7	$1.59
Merger-related expenses, after-tax	(16.0)	(1.19)
Earnings	$5.7	$0.40

The primary drivers of earnings variances for the three years are described in Results of Operations below.

Pending merger-related costs: In 2011, we incurred $27 million in pre-tax merger-related costs, or $1.19 after tax per diluted share of common stock. The majority of these costs are a component of Other Income on the Consolidated Statements of Income.

We discuss the pending Merger with Gaz Métro, our financial initiatives and our key business risks in more detail below.

Tropical Storm Irene: On August 28, 2011, Tropical Storm Irene severely impacted the northeast, including our service territory, resulting in approximately 73,000 CVPS customer outages. In preparation for the storm, we secured outside utility and tree crews from Illinois, Missouri, Texas and Canada, among others and we restored power to our last customer on September 2, 2011. Our storm costs were $9.2 million and we had $1.5 million of related capital expenditures. Of the $9.2 million in costs, $8.4 million was deferred and will be recovered in future rates, beginning on July 1, 2012, under the exogenous cost provision of our alternative regulation plan. See Part II, Item 7, Management's Discussion and Analysis and Results of Operations below for more discussion about the impact on our financial statements.

Acquisitions: In 2011, we expanded our service territory and acquired the Readsboro Electric Department and Vermont Marble Power Division of Omya, Inc. See Part II, Item 7, Management's Discussion and Analysis and Results of Operations, Liquidity, Acquisitions below for additional information.

Financial Initiatives: Our financial initiatives include maintaining sufficient liquidity to support ongoing operations, the dividend on our common stock and investments in our electric utility infrastructure; planning for replacement power when our long-term power contracts expire; and evaluating opportunities to further invest in Transco. Continued focus on these financial initiatives is critical to maintaining our corporate credit rating.

PENDING MERGER

Pending Merger with Métro On July 11, 2011, CVPS, Gaz Métro Limited Partnership ("Gaz Métro ") and Danaus Vermont Corp., an indirect wholly owned subsidiary of Gaz Métro ("Merger Sub"), entered into an Agreement and Plan of Merger (the "Merger Agreement").

Upon the terms and subject to the conditions set forth in the Merger Agreement, unanimously approved by the boards of directors of CVPS and Gaz Métro Inc., the general partner of Gaz Métro , Merger Sub will merge with and into CVPS (the "Merger"), with CVPS continuing as the surviving corporation and an indirect wholly owned subsidiary of Gaz Métro .

Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of CVPS common stock (other than shares which are held by any wholly owned subsidiary of the Company or in the treasury of the Company or which are held by Gaz Métro or Merger Sub, or any of their respective wholly owned subsidiaries, all of which shall cease to be outstanding and shall be canceled and none of which shall receive any payment with respect thereto, and dissenting shares) will automatically be converted into the right to receive in cash, without interest, $35.25 per share (the "Merger Consideration"), less any applicable withholding taxes.

Completion of the Merger is subject to various customary conditions. They include, among others, approval by CVPS shareholders; expiration or termination of the applicable Hart-Scott-Rodino Act waiting period; receipt of all required regulatory approvals from, among others, the FERC and the PSB; and the absence of any governmental action challenging or seeking prohibition of the Merger; and the absence of any material adverse effect with respect to CVPS. Each party's obligation to consummate the Merger is also subject to additional customary conditions including, subject to certain exceptions, the accuracy of the representations and warranties of the other party and performance in all material respects by the other party of its obligations.

The Merger Agreement contains certain termination rights for both CVPS and Gaz Métro and further provides that upon termination of the merger agreement under specified circumstances, CVPS may be required to reimburse Gaz Métro the amount of $19.5 million paid to CVPS by Gaz Métro to reimburse CVPS for a termination payment to FortisUS, Inc. in connection with the termination of a prior merger agreement between CVPS and FortisUS, Inc. A party desiring to terminate must provide written notice of termination to the other party. A notice of termination may be provided at any time after July 11, 2012, if regulatory approval has been obtained at that time but the transaction has not closed in accordance with the Agreement, or January 11, 2013, if regulatory approval has not been obtained by the 12-month anniversary of the Merger Agreement and the transaction has not closed by the 18-month anniversary.

Regulatory Approvals: On September 2, 2011, CVPS, Danaus Vermont Corp., Northern New England Energy Corporation, for itself and as agent for Gaz Métro and the direct and indirect upstream parents of Gaz Métro, GMP, and Vermont Low Income Trust for Electricity, Inc. filed a petition with the PSB for approval of the proposed merger announced by the companies on July 12, 2011. The PSB established a review schedule, beginning with a workshop held on October 14, 2011 and a public hearing on November 1, 2011. Written testimony and discovery responses have been filed with the PSB and technical hearings are scheduled to begin on March 21, 2012 and are currently expected to end on or before April 4, 2012. The hearing schedule may be delayed or extended, at the discretion of the PSB, and there exists no time limit within which the PSB must issue its decision whether to approve the merger.

In addition, we made other regulatory filings seeking approval of the Merger, including with the NRC, the FERC, the Federal Trade Commission, Federal Communications Commission, the Committee on Foreign Investments in the U.S., New York State Public Service Commission, New Hampshire Public Utilities Commission, and the Maine Public Utility Commission. On September 26, 2011, in connection with the Hart Scott-Rodino filing, the Federal Trade Commission granted early termination of the statutory waiting period, which effectively allows us to continue planning for the Merger. On November 22, 2011 we received approvals from the Committee on Foreign Investments in the U.S. and the Maine Public Utility Commission. Also, on November 22, 2011 the New York State Public Service Commission issued a declaratory ruling of no jurisdiction. On March 6, 2012, we received approval from the FERC and on March 7, 2012, we received approval from the Federal Communications Commission for the transfer of control of our radio licenses.

Shareholder Approval: On September 29, 2011, CVPS held a Special Meeting of Shareholders ("Special Meeting"), in Rutland, Vermont. At the meeting, the shareholders approved the Agreement and Plan of Merger, effective as of July 11, 2011, and in a non-binding advisory vote approved the change-in-control payments related to the Merger. Over 75 percent of the outstanding shares of the company were represented at the meeting, and of those, more than 97 percent voted in support of the sale.

Reimbursement of Termination Fee: On September 29, 2011, as a result of the approval by the company's shareholders of the Merger, Gaz Métro reimbursed CVPS for the full amount of the Fortis Termination Payment of $17.5 million plus expenses of FortisUS Inc. of $2 million. Such reimbursement was required pursuant to the terms of CVPS's Merger Agreement with Gaz Métro.

Under the Merger Agreement, CVPS is required to repay the amount of such reimbursement to Gaz Métro in the event the Merger Agreement is terminated because of either the issuance of an order or injunction prohibiting the Merger (other than as a result of the action by a governmental entity with respect to required regulatory approvals) or the breach by CVPS of its representations, warranties or covenants contained in the Merger Agreement. If the Merger Agreement is terminated for any other reason, CVPS is not required to repay such amount to Gaz Métro. While CVPS believes it is unlikely that the Merger Agreement will be terminated on a basis giving rise to a requirement to repay Gaz Métro and, accordingly, believes that the likelihood of such repayment is remote, the final accounting for the reimbursement cannot be determined until the Merger is either completed or terminated. Accordingly, the reimbursement has been recorded as an Other Current Liability until that time.

Terminated Merger Agreement with Fortis On May 27, 2011, CVPS, FortisUS Inc., Cedar Acquisition Sub Inc., a direct wholly owned subsidiary of Fortis ("Merger Sub") and Fortis Inc., the ultimate parent of Fortis ("Ultimate Parent"), entered into an Agreement and Plan of Merger (the "Fortis Merger Agreement").

On July 11, 2011, prior to entering into the Merger Agreement with Gaz Métro, CVPS terminated the Fortis Merger Agreement. In accordance with the Fortis Merger Agreement, on July 12, 2011, CVPS paid FortisUS Inc. $19.5 million (the "Fortis Termination Payment"), consisting of a termination fee of $17.5 million and expenses of FortisUS Inc. of $2 million. These amounts have been recorded as a component of Other Income on the Consolidated Statement of Income in 2011. The Merger Agreement with Gaz Métro required Gaz Métro to reimburse CVPS for its payment of the Fortis Termination Payment immediately following the approval of the Merger Agreement by CVPS shareholders. It also provides that CVPS will be required to pay Gaz Métro the full amount of the Fortis Termination Payment reimbursement if the Merger Agreement is terminated under certain circumstances.

Vendor claim: In June 2011, following our announcement of the Fortis Merger Agreement, we received notice of a claim for up to $4.8 million from a former financial advisor, related to the pending merger. We have assessed the claim and do not believe that any amount is owed. In order to resolve the dispute, on December 23, 2011, we filed a declaratory judgment action in the United States District Court for the District of Vermont, seeking a declaration that we do not owe any amount to the vendor.

Litigation Related to Merger Agreement On or about June 2, 2011, a lawsuit captioned *David Raul v. Lawrence Reilly, et al.*, Civil Division Docket No. 377-6-11-RDCV, was filed in the Superior Court of Vermont, Rutland Unit against CVPS and members of the CVPS Board of Directors. The lawsuit also named as defendants FortisUS Inc. and one of its affiliates. The *Raul* complaint, which purported to be brought on behalf of a class consisting of the public stockholders of CVPS, alleged that CVPS's directors breached their fiduciary duties by entering into the Fortis Merger Agreement for a price that is alleged to be unfair, as the result of a process alleged to be unfair and inadequate, with material conflicts of interest and so as to benefit themselves, and including no-solicitation, matching rights and termination fee provisions alleged to be designed to ensure that no competing offers would emerge for CVPS. The *Raul* complaint also included a claim of aiding and abetting against CVPS and the Fortis entities. The *Raul* complaint sought, among other things, injunctive relief against the proposed transaction with Fortis as well as other equitable relief, damages and attorneys' fees and costs. On June 23, 2011, following the announcement of an offer received from Gaz Métro, David Raul filed an amended class action complaint repeating his earlier allegations and claims but also referring to this development and claiming that the CVPS Board should terminate the Fortis Merger Agreement and negotiate a new deal with Gaz Métro.

On or about June 17, 2011 and June 20, 2011, two additional complaints (Civil Division Docket Nos. 417-6-11-RDCV and 425-6-11-RDCV, respectively) were filed in the Superior Court of Vermont, Rutland Unit, containing claims and allegations similar to those in the original *Raul* complaint and seeking similar relief on behalf of the same putative class. These complaints were filed, respectively, by *IBEW* Local 98 Pension Fund and by Adrienne Halberstam, Jacob Halberstam and Sarah Halberstam.

On July 13, 2011, a lawsuit captioned *Howard Davis v. Central Vermont Public Service, et al.*, Case No. 5:11-CV-181 was filed in the United States District Court for the District of Vermont against CVPS and members of the CVPS Board of Directors. The lawsuit also named as defendants Gaz Métro Limited Partnership and one of its affiliates. The *Davis* complaint, which purported to be brought on behalf of a class consisting of the public stockholders of CVPS, alleged that CVPS's directors breached their fiduciary duties by, among other things, allegedly failing to undertake an adequate sales process prior to the Fortis Merger Agreement, entering into the Merger Agreement with Gaz Métro at an unfair price and pursuant to an unfair process, engaging in self-dealing, and by including various "deal protection devices" in the Merger Agreement. The *Davis* complaint also included a claim for aiding and abetting against CVPS and the Gaz Métro entities. The *Davis* complaint sought injunctive relief and other equitable relief against the proposed transaction with Gaz Métro, as well as attorneys' fees and costs.

On July 22, 2011, the Halberstam plaintiffs in the state case filed an amended complaint in the Vermont Superior Court, Rutland Unit, which added Gaz Métro Limited Partnership and one of its affiliates as defendants in addition to the defendants named in the original complaint. The amended complaint contained claims and allegations similar to those in the *Davis* complaint and sought similar relief.

On August 2, 2011, an Amended Class Action Complaint was filed in the *Davis* action reiterating the previous claims of breaches of fiduciary duty and adding claims that the Company's proxy materials regarding the Merger are materially misleading and/or incomplete in various respects, in alleged violation of fiduciary duties and the federal securities laws. The Amended Class Action Complaint in the *Davis* action seeks injunctive and other equitable relief against the proposed transaction with Gaz Métro, damages, and attorneys' fees and costs.

On or about August 17, 2011, the three cases pending in the Superior Court of Vermont were consolidated by court order, in accordance with a stipulation that had been filed by the parties. The court also entered orders stating that defendants need only respond to a consolidated amended complaint to be filed, denying a motion for expedited discovery that had been brought by the plaintiffs, and staying all discovery until the legal sufficiency of a consolidated amended complaint could be determined.

On August 23, 2011, *IBEW* moved for leave to file a consolidated amended complaint in the state court proceedings. The proposed consolidated amended complaint contained claims for breach of fiduciary duty against the members of the CVPS Board of Directors in connection with both the Fortis Merger Agreement and the subsequent Gaz Métro Merger Agreement, including claims that the proxy materials provided in connection with the proposed shareholder vote on the Merger were misleading and/or incomplete, and that the CVPS Board had violated its fiduciary duties. The proposed consolidated amended complaint also contained claims for aiding and abetting fiduciary breaches against CVPS and Gaz Métro. The proposed consolidated amended complaint sought, among other relief, an injunction against consummation of the Gaz Métro Merger and damages, including but not limited to damages allegedly resulting from CVPS's payment of a termination fee in connection with the termination of the Fortis Merger Agreement.

On September 1, 2011, plaintiff in the *Davis* action filed a motion seeking a preliminary injunction against the September 29, 2011 shareholder vote that was scheduled in connection with the Merger. On September 16, 2011, defendants in the *Davis* action filed motions to dismiss the Amended Class Action Complaint.

On September 19, 2011, CVPS and the other defendants in the *Davis* action entered into a memorandum of understanding with the *Davis* plaintiff regarding an agreed in principle class-wide settlement of the *Davis* action, subject to court approval. In the memorandum of understanding, the parties agreed that CVPS would make certain disclosures to its shareholders relating to the Merger, in addition to the information contained in the initial Proxy Statement, in exchange for a settlement of all claims. Pursuant to the memorandum of understanding, CVPS subsequently issued a Supplemental Proxy statement that included the additional disclosures. On November 28, 2011, the parties to the *Davis* action entered into a finalized settlement agreement consistent with the terms of the memorandum of understanding, which was then submitted to the court by the *Davis* plaintiff together with a request for preliminary approval. The *IBEW* plaintiff subsequently moved to intervene in the *Davis* lawsuit for the purpose of objecting to the proposed settlement agreement. On December 21, 2011, the court held a hearing on the request for preliminary approval and on the *IBEW's* motion to intervene. The request for preliminary approval was denied without prejudice to refile. The *IBEW* motion to intervene was also denied without prejudice.

Meanwhile, a putative class action complaint captioned *IBEW Local 98 Pension Fund, Adrienne Halberstam, Jacob Halberstam, Sarah Halberstam, and David Raul v. Central Vermont Public Service, et al.*, Case No. 5:11-CV-222 was filed in the United States District Court for the District of Vermont against CVPS, Gaz Métro, and members of the CVPS Board of Directors. This federal *IBEW* complaint, dated September 15, 2011, contained claims of breach of fiduciary duty and inadequate proxy statement disclosures that are substantially similar to those contained in the proposed consolidated amended complaint filed by the same plaintiffs in the Superior Court of Vermont. The federal *IBEW* complaint also included allegations of violations of the Securities Exchange Act of 1934. Defendants filed motions to dismiss and, on December 7, 2011, the federal *IBEW* complaint was amended. The amended complaint contains substantially similar claims and allegations. Defendants have moved to dismiss the *IBEW* amended complaint and briefing on that motion has been completed.

On January 12, 2012, the parties to the state court lawsuits filed a stipulation for dismissal without prejudice of those proceedings. On January 24, 2012, the state court entered an order stating that the state court lawsuits would be dismissed without prejudice unless it received a filed objection by January 31, 2012. No such objection was filed.

RETAIL RATES AND ALTERNATIVE REGULATION

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

Alternative Regulation: On September 30, 2008, the PSB issued an order approving our alternative regulation plan. The plan became effective on November 1, 2008. It was scheduled to expire on December 31, 2011. The plan allows for quarterly PCAM adjustments to reflect changes in power supply and transmission-by-others costs and annual base rate adjustments to reflect changes in operating costs; and an annual ESAM adjustment to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity is adjusted annually to reflect one-half of the change in the average yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The ESAM provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to customers in a future period. If the actual return on equity of our regulated business falls between 75 and 125 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and customers. Any earnings shortfall in excess of 125 basis points below the allowed return on equity is fully recovered from customers. As such, the minimum return for our regulated business is 100 basis points below the allowed return. These adjustments are made at the end of each fiscal year.

The ESAM also provides for an exogenous effects provision. Under this provision, we are allowed to defer the unexpected impact if in excess of $0.6 million in the aggregate, of changes in GAAP, tax laws, FERC or ISO-NE rules and major unplanned operation, maintenance costs, such as those due to major storms and other factors including loss of load not due to variations in heating and cooling temperatures. In 2011, we deferred $7.5 million of costs related to Tropical Storm Irene and legislative and tax law changes. We plan to file with the PSB by May 1, 2012, for recovery of these costs commencing on July 1, 2012 as provided by our alternative regulation plan.

By order dated March 3, 2011, the PSB approved amendments to the alternative regulation plan that: 1) extend its duration until December 31, 2013; 2) alter the methodology for implementing the non-power cost cap contained in the plan; 3) reset our allowed ROE to 9.45 percent; and 4) remove provisions no longer applicable to the provision of our services.

Using the methodology specified in our alternative regulation plan, we estimated our 2011 return on equity from the regulated portion of our business to be approximately 9.09 percent. We are required to file this calculation with the PSB by May 1, 2012. No ESAM adjustment was required since this return was within 75 basis points of our 2011 allowed return on equity of 9.45 percent.

The PCAM adjustment for the fourth quarter of 2011 was an over-collection of $0.3 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending June 30, 2012. We filed a PCAM report with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

The PCAM adjustment for the third quarter of 2011 was an under-collection of $0.3 million and was recorded as a current asset. This under-collection will be collected from customers over the three months ending March 31, 2012. We filed a PCAM report with the PSB identifying this under-collection. The DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing.

The PCAM adjustment for the first quarter of 2011was an over-collection of $1 million and for the second quarter of 2011 was an over-collection of $0.8 million. These amounts were recorded as current liabilities and were returned to customers over the three months ending September 30, 2011 for the first quarter and ending December 31, 2011 for the second quarter.

On November 1, 2011, we submitted a base rate filing for the rate year commencing January 1, 2012, as required by our alternative regulation plan. The filing proposes an increase in base rates of $15.8 million or a 4.78 percent increase in retail rates, reflecting an allowed ROE of 9.17 percent. 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, less a productivity adjustment that varies based upon the results of a comparison of certain cost metrics of the company with those of a benchmark group of U.S. electric utilities. For the 2012 rate year, the productivity adjustment was 0.95 percent. The non-power costs associated with the implementation of our Asset Management Plan and our CVPS SmartPower® project are excluded from the non-power cost cap. Our 2012 forecasted non-power costs did not exceed the non-power cost cap. On December 28, 2011, we received approval from the PSB and the 4.78 rate increase went into effect January 1, 2012.

CVPS SmartPower® On October 27, 2009, the DOE announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation.

On April 15, 2010, we signed an agreement with the DOE for our portion of the Smart Grid stimulus grant and project and the agreement became effective April 19, 2010. The agreement includes provisions for funding and other requirements. We are allowed to receive reimbursement of 50 percent of our total eligible project costs incurred since August 6, 2009, up to $31 million. From the inception of the project through December 31, 2011, we have incurred $13.8 million of costs, of which $7.7 million were operating expenses and $6.1 million were capital expenditures. In 2011, we incurred $9.2 million of costs, of which $5.3 million were operating expenses and $3.9 million were capital expenditures.

We have submitted requests for reimbursement of $6.2 million and have received $5 million to date, of which $3.3 million was received in 2011.

On July 19, 2011, we entered into a contract for the communications infrastructure in support of our advanced metering project. The overall contract is approximately $6.2 million for which we are jointly and severally liable with another party. Our share of the contract cost is approximately $3.9 million. The contract calls for a $1.9 million initial payment with remaining payments for certain milestones to be made over a two-year period. In August 2011, we made the initial payment of $1.9 million and received 50 percent reimbursement from the DOE.

Pending Merger with Gaz Métro See Part II, Item 8, Note 1 - Business Organization, Pending Merger with Gaz Métro, Regulatory approvals.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Cash Flows At December 31, 2011, we had cash and cash equivalents of $1.7 million compared to $2.7 million at December 31, 2010.

Our primary sources of cash in 2011 were from our electric utility operations, distributions received from affiliates, income tax refunds, reimbursements from restricted cash of debt-financed project costs, borrowings under our revolving credit facility, net proceeds from the issuance of long-term debt and the Fortis Termination Payment reimbursement from Gaz Métro. Our primary uses of cash in 2011 included the Fortis Termination Payment and merger-related costs, acquisitions of Vermont Marble and Readsboro utility property, capital expenditures, common and preferred stock dividend payments, repayments of borrowings under our revolving credit facility and maturing long-term debt, employee benefit plan funding, and working capital requirements.

Operating Activities: Operating activities provided $45.7 million in 2011, compared to $53.5 million in 2010. The decrease of $7.8 million was primarily due to: a $19.5 million Termination Payment to Fortis; $7.5 million used for merger-related costs; a $6.5 million decrease from special deposits and restricted cash, largely due to $5.4 million of purchased power cash collateral that was replaced with a letter of credit in 2010; a decrease of $2.2 million for interest on long-term debt; and a $1.3 million decrease in working capital and other operating activities. This was partially offset by a $19.5 million Termination Payment reimbursement from Gaz Métro; a $5.2 million increase in distributions received from affiliates; a $3.4 million increase in net income tax refunds; and a $1.1 million recovery of bad debt expense.

At December 31, 2011, our retail customers' accounts receivable over 60 days totaled $3.4 million compared to $2.6 million at December 31, 2010, which was an increase of 28.7 percent.

Investing Activities: Investing activities used $53.4 million in 2011, compared to $91.4 million in 2010. The decrease of $38 million used is due to: a $34.9 million investment in Transco in 2010 versus none in 2011; a $29.8 million increase in restricted cash related to capital projects in 2010 versus no investment in 2011; an $11.2 million increase in reimbursements of restricted cash from bond proceeds; and $0.4 million of various other investing activities. These items were partially offset by an increase of $30.2 million for the acquisitions of Vermont Marble and Readsboro utility property; and an increase of $8.1 million for construction and plant expenditures. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements.

Financing Activities: Financing activities provided $6.7 million in 2011, compared to $38.5 million in 2010. The decrease of $31.8 million is due to: $29.8 million decrease in net proceeds from the issuance of common stock; a $20 million increase in repayment of long-term debt; and a $1 million increase in common stock dividends paid; partially offset by a $10.2 million increase in long-term borrowings; a $8.2 million decrease in net credit facility repayments; and a $0.6 million decrease in common stock offering and debt issue costs.

Transco Based on current projections, Transco expects to need additional equity capital periodically beginning in 2012, but its projections are subject to change based on a number of factors, including revised construction estimates, timing of project approvals from regulators, and desired changes in its equity-to-debt ratio. While we have no obligation to make additional investments in Transco, which are subject to available capital and appropriate regulatory approvals, we continue to evaluate investment opportunities on a case-by-case basis. We are currently considering additional investments of approximately $21 million in 2012, $0 in 2013, $23 million in 2014, $24 million in 2015 and $7 million in 2016, but the timing and amounts depend on the factors discussed above and the amounts invested by other owners.

These capital investments in Transco and our core business provide value to customers and shareholders alike. They provide shareholders with a return on investment while helping to maintain and improve reliability for our customers.

Acquisitions *Vermont Marble Power Division:* On June 10, 2011, the PSB issued an order approving our purchase of the Vermont Marble Power Division of Omya, Inc., pursuant to the purchase and sale agreement and issued a Certificate of Consent. On September 1, 2011, we closed on the transaction. Included in the sale are rights to serve approximately 875 customers, including the Omya industrial facility, which became our single-largest customer representing approximately 6 percent of expected future annual retail sales. The acquisition will create efficiencies that will reduce costs and benefit customers overall; and we acquired renewable hydro assets at competitive costs for our customers.

The agreement also includes a five-year, six-step phase-in of residential rate changes for existing Vermont Marble customers, which will be funded by Omya up to an amount estimated to be approximately $1.1 million.

We will be allowed recovery from customers of up to $27 million for the generating assets and $0.8 million for the transmission and distribution assets. The MOU also requires the creation of a so-called value sharing pool that provides for certain excess value we receive, if any, to be shared among our customers, Omya and our shareholders if energy market prices and hydro facility improvements create more value than anticipated for a period of 15 years following the closing date. This will provide us with an opportunity to recover up to the $1.3 million not otherwise recovered in rates.

We plan to invest an estimated $20 million between 2012 and 2015 to upgrade the Vermont Marble facilities. See Note 19 – Acquisitions.

Readsboro Electric Department: On October 27, 2010, we signed a purchase and sale agreement with Readsboro. The $0.4 million purchase price includes all of the assets of Readsboro including about 14 miles of distribution line and associated equipment, and the exclusive franchise Readsboro holds to serve its 310 customers. On February 24, 2011 we, along with the DPS and Readsboro, filed a stipulation with the PSB that resolves the issues outstanding in our acquisition of Readsboro. On July 8, 2011, the PSB issued an order approving the purchase and sale agreement, and issued a Certificate of Consent. The PSB order does not allow us to recover the acquisition premium of $0.1 million, which is the amount above the net book value of $0.3 million, which approximates fair value. We also assumed a nominal amount of liabilities. On August 1, 2011, we closed on the transaction.

Preferred Stock In accordance with the terms of the Merger Agreement, we plan to redeem all outstanding shares of our preferred stock prior to the closing of the Merger with Gaz Métro, pursuant to the terms of such preferred stock.

Dividends Our dividend level is reviewed by our Board of Directors on a quarterly basis. It is our goal to ensure earnings are sufficient to maintain our current dividend level until we close the merger with Gaz Métro. The Merger Agreement permits us to continue paying our regular quarterly dividend of 23 cents per common share after November 20, 2011, if so declared by the Board of Directors.

Cash Flow Risks Based on our current cash forecasts, we will require outside capital in addition to cash flow from operations and our unsecured revolving credit facilities to fund our business over the next few years. Upheaval in the global capital markets could negatively impact our ability to obtain outside capital on reasonable terms. If we were ever unable to obtain needed capital, we would re-evaluate and prioritize our planned capital expenditures and operating activities. In addition, an extended unplanned power supply outage or similar event could significantly impact our liquidity due to the potentially high cost of replacement power and performance assurance requirements arising from purchases through ISO-NE or third parties. However, this risk has decreased because the New England market has a significant surplus of available energy, due to the significant reductions in natural gas prices, and electrical energy is available at competitive rates. The PCAM within our alternative regulation plan allows recovery of power costs; therefore, in general, power costs would not be expected to materially impact our financial results if the costs are recovered in retail rates in a timely fashion.

Other material risks to cash flow from operations include: loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; significant storm recovery costs; increases in net power costs largely due to lower-than-anticipated margins on sales revenue from excess power or an unexpected power source interruption; required prepayments for power purchases; and increases in performance assurance requirements. It is important to note, however, that our alternative regulation plan allows for recovery of costs related to exogenous events such as significant storm damage and, additionally, sets bands around the earnings in our regulated business, which ensures, in part, that they will not fall below prescribed levels relative to our allowed ROE. See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks.

Global Economic Conditions We expect to have access to liquidity in the capital markets when needed at reasonable rates. We have access to a $40 million unsecured revolving credit facility and a $15 million unsecured revolving credit facility with two different lending institutions. We also have a shelf facility directly with a potential bond purchaser under which we can issue up to $60 million of additional first mortgage bonds to them, though they have no obligation to purchase such bonds. However, sustained turbulence in the global credit markets could limit or delay our access to capital. As part of our enterprise risk management program, we routinely monitor our risks by reviewing our investments in and exposure to various firms and financial institutions.

Financing *Credit Facility:* We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated October 25, 2011 that expires on October 24, 2014. This facility replaced a three-year, $40 million unsecured revolving credit facility that matured on November 2, 2011. The Credit Agreement contains financial and non-financial covenants. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. At December 31, 2011, $3.5 million in letters of credit and $12.3 million in borrowings were outstanding under this credit facility.

We also have a three-year, $15 million unsecured revolving credit facility with a different lending institution pursuant to a Credit Agreement dated December 22, 2010 that expires in December 2013. This facility replaced a 364-day, $15 million unsecured revolving credit facility that matured on December 29, 2010. The purpose and obligation under this credit agreement are the same as described above. We did not use this facility for borrowings or letters of credit during 2010 or 2011.

First Mortgage Bonds: Substantially all of our utility property and plant is subject to liens under our First Mortgage Bond indenture. There are no interim sinking fund payments due prior to maturity on any series of first mortgage bonds and all interest rates are fixed. The First Mortgage Bonds are callable at our option at any time upon payment of a make-whole premium, calculated as the excess of the present value of the remaining scheduled payments to bondholders, discounted at a rate that is 0.5 percent higher than the comparable U.S. Treasury Bond yield, over the early redemption amount.

On June 15, 2011, we issued $40 million of First Mortgage 5.89 percent Bonds, Series WW and $20 million of this amount was used to redeem the Series SS Bonds. The Series WW bonds were issued to one purchaser, in a private placement transaction, under a shelf facility that was put in place on February 4, 2011. The remaining proceeds are being used for our capital expenditures and for other corporate purposes. The shelf facility allows us to issue up to an additional $60 million of first mortgage bonds directly to the purchaser through December 31, 2012. Neither party has any obligation to issue or purchase the additional $60 million first mortgage bonds available under the shelf facility.

Common Equity Issue: On November 6, 2009, we filed a Registration Statement with the SEC on Form S-3, requesting the ability to offer, from time to time and in one or more offerings, up to $55 million of our common stock. On December 4, 2009, the SEC declared the Registration Statement to be effective. On January 15, 2010, we filed a Prospectus Supplement with the SEC noting that we entered into an equity distribution agreement that allowed us to issue up to $45 million of shares under an "at-the-market" program.

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

Industrial/economic development bonds: The CDA and VIDA bonds are tax-exempt, floating rate, monthly demand revenue bonds. There are no interim sinking fund payments due prior to their maturity. The interest rates reset monthly. Both series are callable at par as follows: 1) at our option or the bondholders' option on each monthly interest payment date; or 2) at the option of the bondholders on any business day. There is a remarketing feature if the bonds are put for redemption. Historically, these bonds have been remarketed in the secondary bond market. These two series of bonds are both supported by letters of credit, discussed below.

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

Our first mortgage bond and industrial/economic development bond financing documents do not contain cross-default provisions to affiliates outside of the consolidated entity. Certain of our debt financing documents contain cross-default provisions to our wholly owned subsidiaries, East Barnet and C.V. Realty, Inc. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions, a breach of warranty or performance of an obligation, or the levy of significant judgments, attachments against our property or insolvency. Currently, we are not in default under any of our debt financing documents. Scheduled maturities for the next five years are $0 in 2012, $5.8 million in 2013, $0 in 2014, $5 million in 2015 and $0 in 2016.

Letters of credit: We have two outstanding unsecured letters of credit, issued by one bank, that support the CDA and VIDA revenue bonds. These letters of credit total $11.1 million in support of the two revenue bond issues totaling $10.8 million, discussed above. We pay an annual fee of 2.4 percent on the letters of credit. These letters of credit expire on November 30, 2012. The letters of credit contain cross-default provisions to our wholly owned subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or insolvency. At December 31, 2011, there were no amounts drawn under these letters of credit.

Covenants: At December 31, 2011, we were in compliance with all financial and non-financial covenants related to our various debt agreements, articles of association, letters of credit, credit facilities and material agreements. Some of the typical covenants include:

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

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

The most restrictive financial covenants include maximum debt to total capitalization of 65 percent, and minimum interest coverage of two times interest on first mortgage bonds. At December 31, 2011, our earnings covered our first mortgage bond interest 3.3 times. At December 31, 2011, we had the ability to declare $79.9 million additional dividends or other restricted payments. Also, at December 31, 2011, we were permitted to incur $49.4 million of additional mortgage bond debt and $99.5 million of unsecured debt, of which $99.5 million could be short-term.

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system and our production units. In 2011, capital expenditures were $41.1 million.

Capital expenditures for the years 2012 to 2014 are expected to range from $42 million to $69 million annually, including an estimated total of more than $25.5 million for CVPS SmartPower® over the three-year period. A portion of the CVPS SmartPower® project will be funded by the Smart Grid Stimulus Grant and this grant has reduced the estimated spending range above. Further discussion of the Smart Grid Stimulus Grant can be found above in Retail Rates and Alternative Regulation - CVPS SmartPower®.

Future Liquidity Needs In order to meet our expected levels of capital expenditures and investments in affiliates we expect to need outside capital over the next few years. If the pending merger with Gaz Métro is delayed or is not ultimately consummated, we expect to issue additional debt and equity in 2012.

Performance Assurance We are subject to performance assurance requirements through ISO-NE under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $3 million with ISO-NE. We are required to post collateral for all net power and transmission 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, 2011, we had posted $3.9 million of collateral under performance assurance requirements for certain of our power and transmission transactions, $3.5 million of which was represented by a letter of credit and $0.4 million of which was represented by cash and cash equivalents. At December 31, 2010, we had posted $6.6 million of collateral under performance assurance requirements for certain of our power and transmission transactions, $5.5 million of which was represented by a letter of credit and $1.1 million of which was represented by cash and cash equivalents.

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

Off-balance-sheet arrangements We do not use off-balance-sheet arrangements, such as securitization of receivables, nor do we obtain access to assets through special purpose entities. We have $11.1 million of unsecured letters of credit related to our CDA and VIDA revenue bonds and a $3.5 million letter of credit issued under our $40 million unsecured revolving credit facility. We also have outstanding a $30 million issue of first mortgage bonds, Series VV as security for the $30 million VEDA bonds.

Commitments and Contingencies
Power Supply Matters: We have material power supply commitments for the purchase of power from VYNPC through March 21, 2012 and Hydro-Québec. These are described in Power Supply Matters below.

We own equity interests in VELCO and Transco, which require us to pay a portion of their operating costs under our transmission agreements. We own an equity interest in VYNPC and are obligated to pay a portion of VYNPC's operating costs under the VY PPA between VYNPC and Entergy-Vermont Yankee. We also own equity interests in three nuclear plants that have completed decommissioning. We are responsible for paying our share of the costs associated with these plants. Our equity ownership interests are described in Note 4 - Investments in Affiliates.

Environmental Matters: We are subject to extensive federal, state and local environmental regulations that monitor, among other things, emission allowances, pollution controls, maintenance and upgrading of facilities, site remediation, equipment upgrades and management of hazardous waste. We believe that we are materially in compliance with all applicable environmental and safety laws and regulations; however, there can be no assurance that we will not incur significant costs and liabilities in the future. See Part II, Item 8, Note 18 – Commitments and Contingencies.

On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm. Under the terms of the agreements with Catamount and Diamond Castle Holdings, we agreed to indemnify them, and certain of their respective affiliates as described in Note 13 - Commitments and Contingencies.

Legal Proceedings: We are involved in legal and administrative proceedings, including civil litigation, in the normal course of business as well as a number of lawsuits relating to our pending merger agreement with Gaz Métro that are described above in Pending Merger, Litigation Related to Merger Agreement. We are unable to fully determine a range of reasonably possible court-ordered damages, settlement amounts, and related litigation costs or legal liabilities that would be in excess of amounts accrued and amounts covered by insurance. Based on the information currently available, we do not believe that it is probable that any such legal liability will have a material impact on our consolidated financial position. It is reasonably possible that additional legal liabilities that may result from changes in estimates could have a material impact on our results of operations, financial condition or cash flows. See Part II, Note 1 – Business Organization, Litigation Related to Merger Agreement, for discussion of pending litigation related to the merger.

Contractual Obligations Significant contractual obligations as of December 31, 2011 are summarized below.

Contractual Obligations	Payments Due by Period (dollars in millions) Total	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years
Long-term debt (a)	$240.6	$0.0	$18.1	$5.0	$217.5
Interest on long-term debt (b)	215.9	14.2	27.9	27.3	146.5
Capital lease (c)	3.9	1.2	2.0	0.7	0.0
Operating leases - vehicle and other (d)	3.6	1.4	1.9	0.3	0.0
Purchased power contracts (e)	1,907.8	136.6	185.4	162.4	1,423.4
Nuclear decommissioning and other closure costs (f)	5.2	1.4	2.9	0.9	0.0
Other purchase obligations (g)	0.7	0.7	0.0	0.0	0.0
CVPS SmartPower® (h)	30.5	27.7	2.8	0.0	0.0
Merger Transaction Costs (i)	4.6	4.6	0.0	0.0	0.0
Total Contractual Obligations	$2,412.8	$187.8	$241.0	$196.6	$1,787.4

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

(b) Based on interest rates shown in Part II, Item 8, Note 14 - Long-Term Debt and Notes Payable.

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

(d) Includes interest payments on fixed rates at inception and floating rate issues based on interest rates as of December 31, 2011.

(e) Forecasted power purchases under long-term contracts with Hydro-Québec, VYNPC and various Independent Power Producers. Our current retail rates include a provision for recovery of these costs from customers. The forecasted amounts in this table are based on certain assumptions including plant operations, weather conditions, market power prices and availability of the transmission system; therefore, actual results may differ. See Power Supply Matters for more information.

(f) Estimated decommissioning and all other closure costs related to our equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. Our current retail rates include a provision for recovery of these costs from customers.

(g) Amount represents open purchase orders, excluding those obligations that are separately reported. These payments are subject to change as certain purchase orders include estimates of material and/or services. Because payment timing cannot be determined, we include all open purchase order amounts in 2011. These amounts are not included on our Consolidated Balance Sheet.

(h) The CVPS SmartPower® obligation consists of $25.8 million related to the purchase of our advanced metering infrastructure and $1.9 million related to the communications infrastructure in support of our advanced metering project.

(i) Based on estimated costs from outside service providers related to the merger with Gaz Métro.

CVPS SmartPower®: On April 14, 2011, we entered into a contract for approximately $28.8 million related to our CVPS SmartPower® program for the purchase of our advanced metering infrastructure. We expect to make payments for certain milestones over a two-year period and will seek reimbursement from the DOE for approximately 50 percent of eligible project costs under the eEnergy Vermont SmartGrid Investment Grant.

On July 19, 2011, we entered into a contract for the communications infrastructure in support of our advanced metering project. The overall contract is approximately $6.2 million for which we are jointly and severally liable with another party. Our share of the contract cost is approximately $3.9 million. The contract calls for a $1.9 million initial payment with remaining payments for certain milestones to be made over a two-year period. In August 2011, we made the initial payment of $1.9 million and received 50 percent reimbursement from the DOE.

Long-term Debt: On June 15, 2011, we issued $40 million of First Mortgage 5.89 percent Bonds, Series WW and $20 million was used to redeem the Series SS Bonds. See Financing above for additional information.

Merger Transaction Costs: In 2011, we incurred merger-related costs of $27 million related to the merger agreements with Fortis and Gaz Métro. We estimate additional costs of $4.6 million during the first six months of 2012.

See Pending Merger above for additional information related to a $19.5 million payment we made to Fortis in July 2011, related to the terminated merger agreement fees and expenses, and subsequent reimbursement from Gaz Métro.

For income tax purposes, we are currently deducting all merger transaction costs until such time as the merger is approved by the PSB. At that time, the transaction costs that are facilitative in nature and therefore not deductible will be subject to income tax expense.

Other Future Power Agreements: On July 27, 2011, in cooperation with an energy management firm, we conducted a highly structured Internet auction that involved a dozen pre-screened north-eastern generators and energy marketers. When the bidding closed, we signed three contracts with an average price of approximately $47.50 per megawatt-hour, or 4.75 cents per kilowatt-hour.

The contracts will provide about 570,000 megawatt-hours of energy or about 20 percent of our power supply during the life of the contracts, for $27 million. See Power Supply Matters below for additional information.

Pension and Postretirement Medical Benefit Obligations: The contractual obligation table above excludes estimated funding for the pension obligation reflected in our Consolidated Balance Sheet. In 2012, we expect to contribute a total of $7.1 million to our pension and postretirement medical trust funds. Future payments will vary based on changes in the fair value of plan assets, the benefit obligations and actuarial assumptions. Traditionally, we have recovered these costs through rates. Additional obligations related to our nonqualified pension plans are approximately $0.1 million per year.

Income Taxes: At December 31, 2011, we did not have any uncertain tax position obligations that will result in future cash outflows.

Capitalization Our capitalization for the past two years follows:

	(dollars in thousands)		percent	
	2011	2010	**2011**	2010
Common stock equity	$268,154	$272,728	52%	57%
Preferred stock	8,054	8,054	2%	2%
Long-term debt	240,578	188,300	46%	40%
Capital lease obligations	2,471	3,471	0%	1%
	$519,257	$472,553	100%	100%

Credit Ratings On December 7, 2011, Moody's affirmed our Baa3 corporate issuer rating (an investment-grade rating), our Baa1 senior secured bond rating and our Ba2 preferred stock rating. At the same time, Moody's affirmed our stable rating outlook. Our current credit ratings from Moody's are shown in the table below. Credit ratings should not be considered a recommendation to purchase or sell stock.

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

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

OTHER BUSINESS RISKS

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

We are also subject to regulatory risk and wholesale power market risk related to our Vermont electric utility business.

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

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

Power Supply Risk: While our contract for power purchases from VYNPC ends on March 21, 2012, there is a risk that the plant could be shut down earlier than expected if Entergy-Vermont Yankee determines that it is not economical to continue operating the plant, or due to environmental concerns. While this has been a significant concern in the past, the short span of time before the contract's end and changes in the regional power market have decreased the risk the company might face. The New England Market currently has a significant surplus of available energy and generating capacity, and due to significant reductions in natural gas prices, electrical energy is available at competitive rates.

Hydro-Québec contract deliveries through our current contract end in 2016, with the average level of deliveries decreasing by approximately 20 percent after 2012, and by approximately 84 percent after 2015. In August 2010, we signed a new contract for ongoing Hydro-Québec supplies and it was approved by the PSB in April 2011.

We continue to seek out other power sources but there is a risk that future sources available may not be as reliable and the price of such replacement power could be significantly higher than what we have in place today. However, we have been planning for the expiration of these contracts for several years, and a robust effort, described further below, is in place to ensure a safe, reliable, environmentally beneficial and relatively affordable energy supply going forward. See Power Supply Matters, below.

Wholesale Power Market Price Risk: The majority of our future MWh purchases are through contracts with Hydro-Québec. If this source becomes unavailable for a period of time, there could be exposure to more volatile wholesale power prices and that amount could be material. See Cash Flow Risks above.

We are responsible for procuring replacement energy during periods of scheduled or unscheduled outages of our power sources. Average market prices at the times when we purchase replacement energy might be higher than amounts included for recovery in our retail rates. The PCAM within our alternative regulation plan allows recovery of power costs.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Regulatory Accounting We prepare the financial statements for our utility operations in accordance with FASB guidance for regulated operations. Regulatory assets or liabilities arise as a result of a difference between accounting principles generally accepted in the U.S. and the accounting principles imposed by the regulatory agencies. Generally, regulatory assets represent incurred costs that have been deferred as they are probable of recovery in future rates. In some circumstances, we record regulatory assets before approval for recovery has been received from the regulatory commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base our conclusions on a number of factors including, but not limited to, changes in the regulatory environment, recent rate orders issued and the status of any potential new legislation. Regulatory liabilities represent obligations to make refunds to customers or amounts collected in rates for which the costs have not yet been incurred.

The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may have a material impact on our results of operations. In the event that we determine our regulated business no longer meets the criteria for regulated operations and there is not a rate mechanism to recover these costs, the impact would be, among other things, a charge to operations of $21.2 million pre-tax at December 31, 2011. The continued applicability of accounting for regulated operations is assessed at each reporting period. We believe our regulated operations will be subject to this accounting guidance for the foreseeable future. Also, see Recent Accounting Pronouncements below.

Valuation of Long-Lived Assets We periodically evaluate the carrying value of long-lived assets, including our investments in nuclear generating companies, our unregulated investments, and our interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such an asset is considered impaired when the anticipated undiscounted cash flow from the asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized in the amount by which the carrying value exceeds the fair value of the long-lived asset. No impairments of long-lived assets were recorded in 2011, 2010 or 2009.

Revenues Revenues from the sale of electricity to retail customers are based on PSB-approved rates. Our revenues are recorded when service is rendered or when energy is delivered to customers. We accrue revenue based on estimates of electric service rendered and unbilled revenue at the end of each accounting period. This unbilled revenue is estimated each month based on daily generation volumes (territory load), estimated line losses and applicable customer rates. We estimate line losses at 5.4 percent. A 1 percent change in line losses would result in a $3.2 million change in annual revenues. Factors that could affect the estimate of unbilled revenues include seasonal weather conditions, changes in meter reading schedules, the number and type of customers scheduled for each meter reading date, estimated customer usage by class, applicable customer rates and estimated losses of energy during transmission and delivery. Unbilled revenues totaled $21.6 million at December 31, 2011 and $21 million at December 31, 2010. We believe that these assumptions have resulted in a reasonable approximation of our unbilled revenues and are reasonably likely to continue.

Pension and Postretirement Medical Benefits FASB's accounting guidance for employee retirement benefits requires an employer with a defined benefit plan or other postretirement plan to recognize an asset or liability on its balance sheet for the overfunded or underfunded status of the plan.

We use the fair value method to value all asset classes included in our pension and postretirement medical benefit trust funds. Assumptions are made regarding the valuation of benefit obligations and future performance of plan assets. Delayed recognition of differences between actual results and those assumed is a required principle of these standards. This approach allows for systematic recognition of changes in benefit obligations and plan performance over the working lives of the employees who benefit under the plans. The following assumptions are reviewed annually, with a December 31 measurement date:

Discount Rate: The discount rate is used to record the value of benefits, based on future projections, expressed in today's dollars. The selection methodology used in determining the discount rate includes portfolios of "Aa"-rated bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million in par value. As of December 31, 2011, the pension discount rate changed from 5.75 percent to 5.20 percent and the postretirement medical discount rate changed from 5.25 percent to 4.85 percent. The conditions in the credit market have been volatile since the third quarter of 2008, and further decreases in the discount rates could increase our benefit obligations, which may also result in higher costs and funding requirements.

Expected Return on Plan Assets: We project the future ROA based principally on historical returns by asset category and expectations for future returns, based in part on simulated capital market performance, over the next 10 years. The projected future value of assets reduces the benefit obligation a company will record. The expected long-term ROA assumption was 7.25 percent as of December 31, 2011 and is used to determine the 2012 expense. The ROA assumption was 7.85 percent as of December 31, 2010 and was used to determine the annual expense for 2011.

Rate of Compensation Increase: We project employees' compensation increases, including annual increases, promotions and other pay adjustments, based on our expectations for future long-term experience reflecting general trends. This projection is used to estimate employees' pension benefits at retirement. The projected rate of compensation increase was 4.25 percent in 2011 and in 2010, as of the measurement date.

Post-retirement Health Care Cost Trend: We project expected increases in the cost of health care. We are self-insured, and in recent years have managed costs such that the increases we have experienced have been below the increases at the national level. For measuring annual cost, we assumed an 8 percent annual rate of increase in the per capita cost of covered health care benefits for fiscal 2011, for pre-age 65 and post-age 65 participant claims costs. This annual rate of increase is assumed to remain at 8 percent through 2013, and then the rate is assumed to decrease by 0.5 percent each year, when an estimated ultimate rate of 5 percent is reached in 2019.

Amortization of Gains/(Losses): The assets and liabilities of the pension and postretirement medical benefit plans are affected by changing market conditions as well as differences between assumed and actual plan experience. Such events result in gains and losses. Investment gains and losses are deferred and recognized in pension and postretirement medical benefit costs over a period of years. If, as of the annual measurement date, the plan's unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, the excess is amortized over the average remaining service period of active plan participants. This 10-percent corridor method helps to mitigate volatility of net periodic benefit costs from year to year. Asset gains and losses related to certain asset classes such as equity, emerging-markets equity, high-yield debt and emerging-markets debt are recognized in the calculation of the market-related value of assets over a five-year period. The fixed income assets are invested in longer-duration bonds to match changes in plan liabilities. The gains and losses related to this asset class are recognized in the market-related value of assets immediately. Also see Part II, Item 8, Note 16 - Pension and Postretirement Medical Benefits.

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

	Discount Rate		Return on Assets	
	Increase	**Decrease**	**Increase**	**Decrease**
Pension Plan				
Effect on projected benefit obligation as of December 31, 2011	($2,345)	$2,389	$0	$0
Effect on 2011 net period benefit cost	($214)	($209)	($265)	$265
Other Postretirement Medical Benefit Plans				
Effect on accumulated postretirement benefit obligation as of December 31, 2011	($670)	$703	$0	$0
Effect on 2011 net periodic benefit cost	($67)	$68	($43)	$43

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

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

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

At December 31, 2011, the fair value of money market funds was $0.4 million, the fair value of short-term investments included in restricted cash was $7.2 million and the fair value of decommissioning trust assets was $5.9 million. The fair value of power-related derivatives was an unrealized loss of $4.9 million at December 31, 2011. See Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk for additional information about power-related derivatives and Part II, Item 8, Note 6 – Fair Value.

Derivative Financial Instruments We account for certain power contracts as derivatives under the provisions of FASB's guidance for derivatives and hedging. This guidance requires that derivatives be recorded on the balance sheet at fair value. Derivatives are recorded as current and long-term assets or liabilities depending on the duration of the contracts. Our derivative financial instruments are related to managing our power supply resources to serve our customers, and are not for trading purposes. Contracts that qualify for the normal purchase and sale exception to derivative accounting are not included in derivative assets and liabilities. Additionally, we have not elected hedge accounting for our power-related derivatives.

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

Our power-related derivatives at December 31, 2011 include forward energy contracts and annual and monthly financial transmission rights. All of our power-related derivatives are commodity contracts. For additional information about power-related derivatives, see Part II, Item 8, Note 6 - Fair Value and Note 15 - Power-Related Derivatives.

Income Taxes The application of income tax law is complex and we are required to make many subjective assumptions and judgments in determining our provision for income taxes, deferred tax assets and liabilities, uncertain tax positions and valuation allowances, if applicable. We record income tax expense quarterly using an estimated annualized effective tax rate. Adjustments to these estimates and changes in our subjective assumptions and judgments can materially affect amounts recognized on the statement of operations, balance sheet and statement of cash flows. See Income Tax Matters below.

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

INCOME TAX MATTERS

Capitalized Repairs Project The Capitalized Repairs Project has encompassed the review of 1999 through 2011 property, plant and equipment additions included in Utility Plant on the Consolidated Balance Sheets. The review was performed to identify capitalized additions which could be expensed for tax purposes, resulting in accelerated income tax deductions. During 2011, the Internal Revenue Service notified us that the Congressional Joint Committee on Taxation has allowed our 2009 Capital Repairs deduction in full, ensuring retention of the $13.6 million reduction in taxes the deduction generated. The 2009 Capital Repairs deduction included an Internal Revenue Code Section 481(a) adjustment for the years 1999 through 2008, as well as the adjustment for the 2009 tax year. In 2011, as a result of our Capitalized Repairs Project review of the 2010 and 2011 tax years, we recorded an additional $6.0 million increase in prepayments and deferred income tax liabilities on the Consolidated Balance Sheets.

Tax Bonus Depreciation The Small Business Jobs Act of 2010, which became law on September 27, 2010, extended 50 percent bonus depreciation to 2010. In addition, as a result of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which became law on December 17, 2010, the 50 percent bonus depreciation was extended through 2012, and a 100 percent expensing was allowed for property placed in service after September 8, 2010 through 2011. The combined impact of the additional bonus depreciation allowed as a result of these acts was $4.2 million in 2011 and $6.7 million in 2010. The amounts were recorded to prepayments and deferred income tax liabilities on the Consolidated Balance Sheets. These legislative changes are considered exogenous events and are included in the 2010 and 2011 exogenous effects deferral.

Uncertain Tax Positions As a result of the 2011 allowance in full of our 2009 Capitalized Repairs deduction, we recognized $3.4 million in previously unrecognized tax benefits established during 2010. Because of a limitation on Vermont net operating loss carryforwards for the 2009 tax year, this decrease in unrecognized tax benefits resulted in an increase in the effective tax rate.

Based upon guidance issued by the Internal Revenue Service during 2011, we have concluded that an unrecognized tax benefit is not warranted for our 2010 and 2011 Capitalized Repairs deductions.

RESULTS OF OPERATIONS

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

Our consolidated earnings for 2011 were $5.7 million, or $0.40 per diluted share of common stock. This compares to $21 million, or $1.66 per diluted share of common stock in 2010 and $20.7 million, or $1.74 per diluted share of common stock in 2009.

The tables that follow provide a reconciliation of the primary year-over-year variances in diluted earnings per share for 2011 versus 2010 and 2010 versus 2009. The earnings per diluted share for each variance shown below are non-GAAP measures:

Reconciliation of Earnings Per Diluted Share

	Twelve Months 2011 vs. 2010
2010 Earnings per diluted share	**$1.66**
Major Year-over-Year Effects on Earnings:	
Higher operating revenue - retail sales volume	0.15
Merger-related fees	(1.19)
Recovery of uncollectible accounts in 2010	(0.05)
Variable life insurance	(0.03)
Other (includes impact of additional common shares, income tax adjustments, and various items)	(0.14)
2011 earnings per diluted share	**$0.40**

Reconciliation of Earnings Per Diluted Share

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

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

	Revenues (in thousands)			MWh Sales		
	2011	2010	2009	**2011**	2010	2009
Residential	**$155,784**	$146,835	$139,047	**978,975**	979,922	981,838
Commercial	**116,767**	111,219	104,001	**834,125**	843,156	825,010
Industrial	**41,375**	34,375	32,597	**431,990**	371,591	364,516
Other	**2,087**	1,977	1,884	**6,499**	6,483	6,398
Total retail sales	**316,013**	294,406	277,529	**2,251,589**	2,201,152	2,177,762
Resale sales	**26,185**	37,957	54,279	**679,059**	781,178	840,536
Provision for rate refund	**5,097**	(3,598)	(1,689)	**0**	0	0
Other operating revenues	**12,439**	13,160	11,979	**0**	0	0
Total operating revenues	**$359,734**	$341,925	$342,098	**2,930,648**	2,982,330	3,018,298

The average number of retail customers is summarized below:

	2011	2010	2009
Residential	**136,986**	136,457	136,242
Commercial	**22,911**	22,672	22,577
Industrial	**35**	35	36
Other	**174**	174	175
Total	**160,106**	159,338	159,030

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

	2011 vs. 2010	2010 vs. 2009
Retail sales:		
Volume (MWh)	**$4,267**	$2,674
Average price due to customer sales mix	**(4,384)**	933
Average price due to rate increases	**21,724**	13,270
Subtotal	**21,607**	16,877
Resale sales	**(11,772)**	(16,322)
Provision for rate refund	**8,695**	(1,909)
Other operating revenues	**(721)**	1,181
Change in operating revenues	**$17,809**	($173)

<u>2011 vs. 2010</u>
Operating revenues increased by $17.8 million, or 5.2 percent, due to the following factors:

- Retail sales increased $21.6 million in 2011 resulting primarily from a 7.46 percent base rate increase effective January 1, 2011, the acquisition of Vermont Marble on September 1, 2011, higher customer usage due to colder weather in early 2011, partially offset by weaker customer demand in the end of 2011 due to warmer weather and decreased snow-making.
- Resale sales decreased $11.8 million in 2011 due to lower 2011 contract prices associated with the sale of our excess energy and lower volume available for resale due to higher retail load.
- The provision for rate refund increased $8.7 million in 2011 primarily due to net over-collections of power, production and transmission costs as defined by the power cost adjustment clause of our alternative regulation plan. This increase included the favorable impact of $5.1 million of net deferrals and refunds in 2011 vs. the unfavorable impact of $3.6 million of net deferrals and refunds in 2010.
- Other operating revenues decreased $0.7 million in 2011 mostly due to lower transmission revenue and lower sales of renewable energy credits.

2010 vs. 2009

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

- Retail sales increased $16.9 million resulting primarily from a 5.58 percent base rate increase effective January 1, 2010 and the recovery of 2008 major storm costs through the ESAM, in addition to a resurgence of retail load in the second half of 2010.
- Resale sales decreased $16.3 million due to lower 2010 contract prices associated with the sale of our excess energy and a decrease in volumes sold due to the scheduled refueling outages at the Vermont Yankee plant and Millstone Unit #3.
- The provision for rate refund decreased $1.9 million primarily due to over- or under-collections of power, production and transmission costs as defined by the power cost adjustment clause of our alternative regulation plan. This decrease included the unfavorable impact of $3.6 million of net deferrals and refunds in 2010 vs. the unfavorable impact of $1.7 million of net deferrals and refunds in 2009.
- Other operating revenues increased $1.2 million mostly from higher levels of mutual aid to other utilities in 2010 and the sale of renewable energy credits.

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

	2011 over/(under) 2010		2010 over/(under) 2009	
	Total Variance	Percent	Total Variance	Percent
Purchased power - affiliates and other	**($3,815)**	**-2.4%**	$2,792	1.8%
Production	**(810)**	**-6.9%**	378	3.3%
Transmission - affiliates	**14,939**	*	(11,790)	*
Transmission - other	**360**	**1.4%**	2,853	12.0%
Other operation	**217**	**0.4%**	(2,518)	-4.3%
Maintenance	**7,620**	**25.5%**	5,639	23.3%
Depreciation	**1,736**	**9.9%**	649	3.8%
Taxes other than income	**1,042**	**6.0%**	745	4.5%
Income tax expense	**(2,378)**	**-31.5%**	2,512	49.9%
Total operating expenses	**$18,911**	**5.8%**	$1,260	0.4%

* variance exceeds 100 percent

Purchased Power - affiliates and other: Power purchases made up 46 percent of total operating expenses in 2011 and 49 percent of total operating expenses in both 2010 and 2009. Most of these purchases are made under long-term contracts. These contracts and other power supply matters are discussed in more detail in Power Supply Matters below. Purchased power expense and volume are summarized below:

	Purchases (in thousands)			MWh purchases		
	2011	2010	2009	**2011**	2010	2009
VYNPC	**$62,394**	$58,715	$64,017	**1,420,705**	1,384,551	1,551,925
Hydro-Quebec	**61,933**	62,971	63,095	**922,901**	963,027	919,764
Independent Power Producers	**23,475**	22,859	22,559	**194,161**	195,325	202,483
Subtotal long-term contracts	**147,802**	144,545	149,671	**2,537,767**	2,542,903	2,674,172
Other purchases	**8,858**	16,146	7,209	**102,319**	174,175	59,037
Reserve for loss on power contract	**(1,196)**	(1,196)	(1,196)	**0**	0	0
Nuclear decommissioning	**1,404**	1,379	1,312	**0**	0	0
Other	**91**	(100)	986	**0**	0	0
Total purchased power	**$156,959**	$160,774	$157,982	**2,640,086**	2,717,078	2,733,209

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

	2011 vs. 2010	2010 vs. 2009
VYNPC	**$3,679**	($5,302)
Hydro-Quebec	**(1,038)**	(124)
Independent Power Producers	**616**	300
Subtotal long-term contracts	**3,257**	(5,126)
Other purchases	**(7,288)**	8,937
Reserve for loss on power contract	**0**	0
Nuclear decommissioning	**25**	67
Other	**191**	(1,086)
Total purchased power	**($3,815)**	$2,792

2011 vs. 2010
Purchased power expense decreased $3.8 million, or 2.4 percent due to the following factors:

- Purchased power costs under long-term contracts increased $3.3 million in 2011, due primarily to higher output at the Vermont Yankee plant and increased purchases from Independent Power Producers.
- Other purchases decreased $7.3 million in 2011 due to lower capacity costs and decreased volumes needed to supplement load requirements.
- Other costs increased by $0.2 million in 2011. These Other costs are amortizations and deferrals based on PSB-approved regulatory accounting, including those for incremental energy costs related to Millstone Unit #3 scheduled refueling outages and deferrals for our share of nuclear insurance refunds received by VYNPC.

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

- Purchased power costs under long-term contracts decreased $5.1 million in 2010, due primarily to lower output at the Vermont Yankee plant related to an extended scheduled refueling outage, lower capacity costs from Hydro-Québec and decreased purchases from Independent Power Producers.
- Other purchases increased $8.9 million due to higher retail load sourced with increased volumes at higher market prices and the purchase of replacement power for the scheduled refueling outages at Vermont Yankee and Millstone Unit #3.
- Nuclear decommissioning costs increased $0.1 million associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs are based on FERC-approved tariffs.
- Other costs decreased $1.1 million. These Other costs are amortizations and deferrals based on PSB-approved regulatory accounting, including those for incremental energy costs related to Millstone Unit #3 scheduled refueling outages and deferrals for our share of nuclear insurance refunds received by VYNPC.

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

The decrease of $0.8 million in 2011 was due to $0.5 million of lower Vermont Yankee outage insurance for 2010 versus 2011 since it ended in March 2011, and various other items. There was no significant variance for 2010 versus 2009.

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

The increase of $14.9 million in 2011 was principally due to higher VTA billings due to increased cost of service and specific facility charges, and lower NOATT reimbursements under the VTA. The decrease of $11.8 million for 2010 versus 2009 was principally due to higher NOATT reimbursements under the VTA, related to the overall transmission expansion in New England, partially offset by higher charges under the VTA resulting from Transco's capital projects.

Other operation: These expenses are related to operating activities such as customer accounting, customer service, administrative and general activities, regulatory deferrals and amortizations and other operating costs incurred to support our core business. The increase of $0.2 million in 2011 was primarily due to $1.8 million of higher bad debt expense, primarily due to a customer bankruptcy in 2009 and subsequent bad debt recoveries of $1.1 million in 2010; higher reserves for uncollectible accounts, resulting from an increase in customer receivables over 60 days; and $0.8 million of higher regulatory commission costs, related to the pending merger in 2011. These increases were partially offset by $2.3 million of lower net regulatory amortizations, largely due to an exogenous effect deferral entry recorded in 2011, principally related to Tropical Storm Irene. The decrease of $2.5 million for 2010 versus 2009 was primarily due to $1.6 million of lower net regulatory amortizations, largely due to an exogenous effect deferral entry of $4.2 million recorded in 2010, comprised of $3.4 million related to major storms and $0.8 million related to income taxes. We also had $2.1 million of lower reserves for uncollectible accounts, primarily due to a large customer bankruptcy in 2009 and subsequent recovery of $1.1 million in 2010. These decreases were partially offset by $1.2 million of higher employee benefit costs, including higher pension and active employee medical costs, partially offset by lower retiree medical costs.

Maintenance: These expenses are associated with maintaining our electric distribution system and include costs of our jointly owned generation and transmission facilities. The increase of $7.6 million was largely due to higher service restoration costs in 2011, including a major tropical storm in August 2011 vs. major storms in 2010. We were able to defer $8.4 million of these costs as an exogenous effect deferral as described above in Other operation. The increase of $5.6 million for 2010 versus 2009 was largely due to higher service restoration costs related to major storms in 2010. We were able to defer $3.4 million of these costs as an exogenous effect deferral as described above in Other operation.

Depreciation: We use the straight-line remaining-life method of depreciation. The increase of $1.7 million was due to a higher level of utility plant assets and the acquisition of the Vermont Marble service territory. The increase of $0.6 million for 2010 versus 2009 was due to a higher level of utility plant assets.

Taxes other than income: This is related primarily to property taxes and payroll taxes. The increase of $1 million was largely due to increases in property taxes resulting from higher rates and more property subject to taxes resulting from the acquisition of the Vermont Marble service territory. The increase of $0.7 million for 2010 versus 2009 was largely due to increases in property taxes.

Income tax (benefit) expense: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods. The effective combined federal and state income tax rate for 2011 is 40.1 percent compared to 41.2 percent for 2010 and 34 percent for 2009. The variance includes the impact of low pre-tax earnings in 2011 combined with a $0.2 million unfavorable prior year true-up recorded in 2011, and the impact of the PPACA, as modified by the Health Care and Education Reconciliation Act. Also, see Part II, Item 8, Note 17 – Income Taxes.

Other Income and Other Deductions These items are related to the non-operating activities of our utility business and the operating and non-operating activities of our non-regulated businesses through CRC. CRC's earnings were $0.2 million in 2011, $0.4 million in 2010, $0.9 million in 2009. Significant variances in line items that comprise other income and other deductions on the Consolidated Statements of Income are described below.

	2011 over/(under) 2010		2010 over/(under) 2009	
	Total Variance	**Percent**	Total Variance	Percent
Equity in earnings of affiliates	**$6,635**	**31.5%**	$3,626	20.8%
Allowance for equity funds during construction	**(1)**	**-0.8%**	(42)	-26.1%
Other income	**(449)**	**-13.9%**	308	10.5%
Other deductions	**(26,714)**	*	(699)	44.1%
Income tax expense	**8,473**	*	(1,477)	26.2%
Total other income and deductions	**($12,056)**	**-80.1%**	$1,716	12.9%

* variance exceeds 100 percent

Equity in earnings of affiliates: These are earnings on our equity investments including VELCO, Transco and VYNPC. The increase of $6.6 million for 2011 versus 2010 is principally due to the return on the $34.9 million investment that we made in Transco in December 2010. The increase of $3.6 million for 2010 versus 2009 is principally due to the $20.8 million investment that we made in Transco in December 2009.

Other income: These items include interest and dividend income on temporary investments, non-utility revenues relating to rental water heaters, and miscellaneous other income. The decrease of $0.4 million for 2011 versus 2010 resulted primarily from lower non-utility revenues and lower interest and dividend income. The increase of $0.3 million for 2010 versus 2009 resulted primarily from higher non-utility revenues and higher interest and dividend income.

Other deductions: The increase of $26.7 million in 2011 is primarily related to a $19.5 million termination payment to Fortis Inc., $6.5 million of expenses for outside counsel and investment advisors related to the merger agreements with Fortis and Gaz Métro, and $0.4 million related to changes in the cash surrender value of variable life insurance policies included in our Rabbi Trust, resulting from higher market losses. The increase of $0.7 million for 2010 versus 2009 is related to changes in the cash surrender value of variable life insurance policies. In 2010, there were market losses versus market gains in 2009.

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

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

	2011 over/(under) 2010		2010 over/(under) 2009	
	Total Variance	**Percent**	Total Variance	Percent
Interest on long-term debt	**$2,142**	**19.2%**	$24	0.2%
Other interest	**21**	**4.6%**	9	2.0%
Allowance for borrowed funds during construction	**(71)**	*	45	-42.5%
Total interest expense	**$2,092**	**18.1%**	$78	0.7%

* variance exceeds 100 percent

Interest on long-term debt: The increase of $2.1 million in 2011 is principally due to interest on long-term debt from bond issuances in December 2010 and June 2011, and repayment of long-term debt in June 2011. There was no significant variance for 2011 versus 2010 or for 2010 versus 2009.

Inflation The annual rate of inflation for the past three years, as measured by the Consumer Price Index, has been minimal; therefore, inflation has not materially affected our results of operation and financial condition for the periods.

POWER SUPPLY MATTERS

Power Supply Management Our power supply portfolio includes a mix of baseload, dispatchable resources and intermittent resources. These resources serve our retail electric load requirements and wholesale obligations. We manage our power supply portfolio by attempting to optimize the economic value of these resources and create a balance between our power supplies and load obligations.

Our power supply management philosophy is to strike a balance between cost and risk. We strive to minimize power costs while keeping liquidity risks at conservative levels. Risk mitigation strategies are built around minimizing both forward price risks and operational risks while limiting the potential for both our collateral exposure and inefficient deployment of capital. Other risks are mitigated by the power and transmission cost recovery process contained in the PCAM (see Retail Rates and Alternative Regulation). We also seek to reduce net power costs and mitigate price risks through limited wholesale transactions primarily to sell excess energy and to occasionally cover anticipated energy shortfalls. FTR auctions provide us with opportunities to economically hedge our exposure to congestion charges that result from transmission system constraints between generator resources and load areas. FTRs are awarded to successful bidders in periodic auctions that are administered by ISO-NE.

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

	2011	2010	2009
Nuclear	52%	50%	55%
Hydro	40%	40%	38%
Oil and wood	3%	4%	4%
Other	5%	6%	3%
Total	**100%**	100%	100%

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

Our current power and load forecasts suggest we have committed energy supplies in 2012 that are in balance with expected load. In 2011, we conducted a successful online auction to sell most of our projected excess energy for 2011 and early 2012 in the forward market, on a unit-contingent basis, at fixed prices in order to reduce market price volatility and gain a measure of revenue certainty while remaining strictly within potential collateral exposure limits.

Attaining an investment-grade credit rating expanded the available collateral limits with our current counterparties and we have attracted additional counterparties that appear willing to transact with us. However, regardless of collateral limits and available counterparties, we expect to maintain our practice of constraining net transaction volumes with individual counterparties to mitigate potential collateral exposures during stressed market conditions.

Vermont Yankee: We are purchasing our entitlement share of Vermont Yankee plant output through the VY PPA between Entergy-Vermont Yankee and VYNPC. We have one secondary purchaser that receives less than 0.5 percent of our entitlement. Our contract for purchases expires on March 21, 2012. While this has been a significant concern in the past, the short span of time before the contract's end and changes in the regional power market have decreased the risk the company might face. The New England Market currently has a significant surplus of available energy and generating capacity, and due to significant reductions in natural gas prices, electrical energy is available at competitive rates.

In recent years, prices under the VY PPA increased $1 per megawatt-hour each calendar year and were $44 per MWh in 2011 and are $45 per MWh in 2012. The VY PPA contains a provision known as the "low market adjuster" that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. Purchases in 2012 are expected to be approximately $15.6 million. The total cost estimate is based on projected MWh purchase volume at PPA rates, plus an estimate of VYNPC's costs and credits, primarily net interest, nuclear insurance refunds and administration. Actual amounts may differ. See Note 4 – Investments in Affiliates for additional information on the VY PPA.

Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. We purchase replacement energy as needed when the Vermont Yankee plant is not operating or is operating at reduced levels. We typically acquire most of this replacement energy through forward purchase contracts and account for those contracts as derivatives. Also, see Future Power Agreements below for additional information regarding new contracts to fill the gap in our portfolio created by the end of our existing contract with Vermont Yankee.

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

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

On January 10, 2012, after failing to reach a resolution of the matter with Entergy-Vermont Yankee, we and GMP filed a lawsuit in Vermont Superior Court in Windham County. The lawsuit seeks compensatory damages of $6.6 million to cover increased power costs and lost capacity payments resulting from the tower failures, plus interest. Our portion of this claim is $4.3 million. On January 18, 2012, Defendant Entergy-Vermont Yankee filed a notice of removal of the case to the United States District Court for the District of Vermont, asserting diversity of citizenship and federal jurisdiction over a federal question. The defendant also filed an answer to the complaint, and asserted affirmative defenses and demanded a jury trial. The case is now pending in the federal court. We cannot predict the outcome of this matter at this time.

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

Coincident with the termination of the VY PPA on March 21, 2012 is the termination of the Vermont Yankee plant's original 40-year operating license. While the NRC voted 4-0 to approve the 20-year license extension through March 21, 2032 requested by Entergy-Vermont Yankee, under Act 160, a Vermont law enacted in 2006, a favorable Vermont legislative vote was required for the Vermont Yankee plant to continue operations after March 21, 2012. 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.

In a federal lawsuit filed in U.S. District Court for the District of Vermont on April 18, 2011, Entergy-Vermont Yankee contended that the state was improperly attempting to interfere with its relicensing and sought a judgment to prevent the state of Vermont from forcing the Vermont Yankee nuclear power plant to cease operation on March 21, 2012. The complaint sought both declaratory and injunctive relief, and contended that Vermont's attempts to close the plant are preempted by the Atomic Energy Act, the Federal Power Act and the Commerce Clause of the U.S. Constitution.

During the week of September 12, 2011, the U.S. District Court for the District of Vermont held a trial on the merits of Entergy-Vermont Yankee's complaint.

On January 19, 2012, the U.S. District Court for the District of Vermont issued a decision ruling against the state of Vermont. The effect of the ruling is that the state is prohibited under federal law from taking any action to compel the plant to shut down after March 21, 2012 because it failed to obtain legislative approval (under the provisions of Act 160). The state of Vermont was precluded from shutting the plant down for safety-related reasons. On February 18, 2012, the state filed a notice of appeal with the 2nd U.S. Circuit Court of Appeals in New York. Meanwhile, Vermont Yankee still must obtain a Certificate of Public Good from the PSB to gain a 20-year license extension. We are participants in this docket due to a prior revenue-sharing agreement. That revenue-sharing arrangement provides in part that in the event that Entergy extends the operation of the plant pursuant to an extension of its NRC license, Entergy agrees to share with VYNPC 50 percent of the "Excess Revenue" for 10 years commencing on March 13, 2012.

On February 27, 2012, Entergy filed notice with the U.S. District Court for the District of Vermont saying that it would ask the 2nd U.S. Circuit Court of Appeals to review a decision. It will appeal a federal judge's order allowing the plant to stay open past its originally scheduled shutdown date, and will ask the original judge to revisit his order and prevent the state of Vermont from barring the future storage of spent nuclear fuel at the plant. Entergy has informed the PSB that it intends to continue to operate the plant pending a final PSB ruling on its operation. The PSB has not yet indicated whether it will require the plant to cease operations after March 21.

VYNPC DOE Litigation: VYNPC has been seeking recovery of fuel storage-related costs from the DOE. Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the disposal of spent nuclear fuel and high-level radioactive waste. VYNPC, as required by that Act, signed a contract with the DOE (the "Standard Contract") to provide for the disposal of spent nuclear fuel and high-level radioactive waste from its nuclear generation station beginning no later than January 31, 1998. The Standard Contract obligated VYNPC to pay a one-time fee of approximately $39.3 million for disposal costs for all nuclear fuel used through April 6, 1983 (the "pre-1983 fuel"), and a fee payable quarterly equal to one mil per kilowatt-hour of nuclear generated and sold electricity after April 6, 1983. Except for the obligation to pay the one-time fee and the right to claims relating to the DOE's defaults under the Standard Contract with respect to the pre-1983 fuel, the Standard Contract was assigned to Entergy effective with the sale of the plant in 2002. VYNPC filed its lawsuit against the government for the DOE's breach in the U.S. Court of Federal Claims on July 30, 2002.

Through 2011, VYNPC has accumulated $143 million in an irrevocable trust to be used exclusively for meeting this obligation ($144.7 million including accrued interest) at some future date, provided the DOE complies with the terms of the aforementioned Standard Contract. Under the terms of the sale agreement, VYNPC retained the spent fuel trust fund assets, the related obligation to make this payment to the DOE when and if it becomes due, and its claims against DOE associated with the pre-1983 fuel. VYNPC 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.

On October 22, 2008, the trial judge presiding over VYNPC's case granted a motion for partial summary judgment filed by Entergy, and dismissed VYNPC's case. The judge ruled that VYNPC lacked any actionable claim that was not transferred to Entergy in the sale of the plant. On April 3, 2009, the trial judge reissued his decision to dismiss VYNPC's case under a special rule that would allow VYNPC to immediately appeal the decision to the United States Court of Appeals for the Federal Circuit ("the Federal Circuit"). However, on September 2, 2009, the Federal Circuit remanded the matter to the trial judge with instructions to vacate his most recent ruling. The effect of this action was to suspend VYNPC's appeal until the trial judge issued a final order in the related Entergy proceeding. The order was issued on October 15, 2010, and on December 13, 2010, VYNPC filed a Notice of Appeal to the Court of Appeals for the Federal Circuit.

In its appeal, VYNPC filed a legal brief on May 12, 2011, and it was followed by amicus curiae ("friend of the court") briefs from the state of Vermont on May 19, 2011 and October 24, 2011. Reply briefs were filed by the DOE on December 5, 2011, VYNPC on December 22, 2011, and Entergy Nuclear-Vermont Yankee on January 4, 2012. The appeal is still pending.

We expect that our share of these awards, if any, would be credited to our retail customers; however, we are currently unable to predict the outcome of this case.

Hydro-Québec: We continue to purchase power under the Hydro-Québec VJO power contract. The VJO power contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between us and Hydro-Québec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO power contract runs through 2020, but our purchases under the contract end in 2016. The average level of deliveries under the current contract decreases by approximately 20 percent after 2012, and by approximately 84 percent after 2015.

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

There are two sellback contracts with provisions that apply to existing and future VJO power contract purchases. The first resulted in the sellback of 25 MW of capacity and associated energy through April 30, 2012, which has no net impact currently since an identical 25 MW purchase was made in conjunction with the sellback. We have a 23 MW share of the 25 MW sellback. However, since the sellback ends six months before the corresponding purchase ends, the first sellback will result in a 23 MW increase in our capacity and energy purchases for the period from May 1, 2012 through October 31, 2012.

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Québec. The first option was never exercised and expired December 31, 2010. The second gives Hydro-Québec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Québec. This second option can be exercised five times through October 2015 but due to the notice provision there is a maximum remaining application of three times available. To date, Hydro-Québec has not exercised this option. We have determined that this second option is not a derivative because it is contingent upon a physical variable.

There are specific contractual provisions providing that in the event any VJO member fails to meet its obligation under the contract with Hydro-Québec, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2011, our obligation is about 47 percent of the total VJO power contract through 2016, and represents approximately $226.8 million, on a nominal basis.

In accordance with FASB's guidance for guarantees, we are required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. With regard to the "step-up" provision in the VJO power contract, we must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. We believe this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power contract in its most recent rate applications. Despite the remote chance that such an event could occur, we estimate that our undiscounted purchase obligation would be an additional 265.2 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2012 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.

Independent Power Producers: We receive power from several IPPs, primarily so-called small power producers. 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. Starting in 2012, we will also purchase power from some larger independent producers, primarily wind projects. Estimated annual purchases are expected to increase from $23.5 million in 2011 to about $35 million in 2012 and up to $47 million by 2016. These cost estimates are based on assumptions regarding the number, sizes and types of IPPs that we purchase from, hydrological and wind conditions and other factors, so actual amounts could be higher or lower. Our total purchases from IPPs were $23.5 million in 2011, $22.9 million in 2010 and $22.6 million in 2009.

Wholly owned hydro and thermal: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of 90.3MW. These plants include 24 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.05 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 63.8 MW and two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW.

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

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

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

In January 2004 DNC filed, on behalf of itself and the two minority owners, including us, a lawsuit against the DOE seeking recovery of costs related to the storage of spent nuclear fuel arising from the failure of the DOE to comply with its obligations to commence accepting such fuel in 1998. A trial commenced in May 2008. On October 15, 2008, the United States Court of Federal Claims issued a favorable decision in the case, including damages specific to Millstone Unit #3. The DOE appealed the court's decision in December 2008. On February 20, 2009, the government filed a motion seeking an indefinite stay of the briefing schedule. On March 18, 2009, the court granted the government's request to stay the appeal. On November 19, 2009, DNC filed a motion to lift the stay. On April 12, 2010, the stay was lifted and a staggered briefing schedule was proposed, to which DNC has responded with a request to expedite the briefing schedule so that the appeals of all parties can be heard concurrently.

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

On April 25, 2011 the U.S. Court of Appeals for the Federal Circuit issued a decision affirming the spent fuel damages award for damages incurred through June 30, 2006 in connection with DOE's failure to begin accepting spent fuel for disposal. The government had the option to seek rehearing of the Federal Circuit decision and to seek review by the U.S. Supreme Court. The time period for seeking rehearing was 45 days.

On June 30, 2011, DNC informed us that the DOE decided not to seek rehearing and instead wishes to pay the awarded damages. In October 2011 we received $0.2 million and that amount was credited to our retail customers.

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

ISO-NE has a market mechanism referred to as the FCM to compensate owners of qualifying generation capacity, including demand response. Capacity requirements for load-serving entities, including us, are currently based on each entity's percentage share of ISO-NE's prior year coincident peak demand and the total pool capacity requirement. Net FCM charges in 2011 were about $1.5 million. In 2012 we expect net FCM charges of about $5 million due in large part to the expiration of our power contract with Vermont Yankee, which provided close to 180 MW of FCM credit per month in 2011.

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

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

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

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

On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. Technical hearings were held and final legal briefs were filed in the first quarter of 2011. On April 15, 2011 the PSB issued an order approving the HQUS PPA.

Under the HQUS PPA, we are entitled to purchase an energy quantity of up to 5 MW from November 1, 2012 to October 31, 2015; 90.4 MW from November 1, 2015 to October 31, 2016; 101.4 MW from November 1, 2016 to October 31, 2020; 103.4 MW from November 1, 2020 to October 31, 2030; 112.8 MW from November 1, 2030 to October 31, 2035; and 27.4 MW from November 1, 2035 to October 31, 2038. These quantities include assumption of Vermont Marble's allocations as a result of our September 1, 2011 purchase of Vermont Marble.

Other Future Power Agreements: As we continue to build and diversify our power portfolio as planned and to comply with state law which establishes goals for including renewable power in our mix, we have signed several agreements for clean and competitively priced renewable energy. On September 9, 2010 we agreed to terms for purchasing output over nine years from Iberdrola Renewables' planned Deerfield Wind Project. The agreement was signed by the parties on December 13, 2010. The project has experienced delays in receiving a necessary permit from the U.S. Forest Service and construction is not now scheduled to take place in a manner that would be sufficient for meeting the conditions precedent of the agreement. The developer received the permit, but it was too late for completion of the project in 2012, and the project is now on hold. Conditions precedent not satisfied or waived on or before April 1, 2012 could result in termination of the contract by June 30, 2012. We are currently in discussions with Iberdrola, the parent company, with respect to terminating, reforming or replacing the agreement.

Other agreements signed in 2010 include: two separate agreements to purchase 30.3 percent of the actual output from Granite Reliable Wind project for 20 years beginning April 1, 2012 and an additional 20 percent for 15 years beginning in November 2012; an agreement to purchase the entire 4.99 MW output of Ampersand Gilman Hydro for five years starting April 1, 2012; and 15 MW of around-the-clock energy from J.P. Morgan Ventures Energy for the calendar years 2013 through 2015.

On July 27, 2011, in cooperation with an energy management firm, we conducted a highly structured Internet auction that involved a dozen pre-screened northeastern generators and energy marketers. When the bidding closed, we signed three contracts with an average price of approximately $47.50 per megawatt-hour, or 4.75 cents per kilowatt-hour.

Two of the contracts will fill the 2012 gap in our portfolio created by the end of our existing contract with Vermont Yankee. One will supply energy 24 hours per day from April 1, 2012 through the end of the year, while the other will provide both peak and off-peak power during specific periods in 2012 when we have remaining supply gaps. The third contract filled our energy needs during the planned Vermont Yankee refueling outage that ended November 3, 2011.

These purchase contracts will provide about 570,000 megawatt-hours of energy or about 20 percent of our power supply during the life of the contracts, for $27 million. The contracts are for so-called "system power," meaning they are not conditioned on the operation of individual power generation sources.

In September 2011, we also used the auction process to sell small amounts of projected excess energy to hedge price risks during the first two months of 2012.

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

Based on estimates from Maine Yankee, Connecticut Yankee and Yankee Atomic as of December 31, 2011, the total remaining approximate cost for decommissioning and other costs of each plant is as follows: $18.8 million for Maine Yankee, $175.2 million for Connecticut Yankee and $39.4 million for Yankee Atomic. Our share of the remaining obligations amounts to $0.4 million for Maine Yankee, $3.5 million for Connecticut Yankee and $1.4 million for Yankee Atomic. These estimates may be revised from time to time based on information available regarding future costs.

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

In 2006, the United States Court of Federal Claims issued judgment in the first phase of 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. This decision was appealed in December 2006, 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 the 1987 annual capacity reports when determining damages.

A final ruling on the remanded case in favor of the three companies was issued on September 7, 2010. Maine Yankee was awarded $81.7 million, Connecticut Yankee was awarded $39.7 million and Yankee Atomic was awarded $21.2 million. The DOE filed an appeal on November 8, 2010 and the three Yankee companies filed cross-appeals on November 19, 2010.

Oral arguments before the United States Court of Appeals for the Federal Circuit were held on November 7, 2011. The court has yet to issue a decision. Interest on the judgments does not start to accrue until the appeals have been decided. Our share of the claimed damages of $3.2 million is based on our ownership percentages described above.

The Court of Federal Claims' original decision established the DOE's responsibility for reimbursing Maine Yankee for its actual costs through 2002 and Connecticut Yankee and Yankee Atomic for their actual costs through 2001. These costs are related to the incremental spent fuel storage, security, construction and other expenses 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, the three companies filed a second round of damage cases against the DOE. On July 1, 2009, Maine Yankee, Connecticut Yankee and Yankee Atomic filed details related to the claimed costs for damages incurred for periods subsequent to the original case discussed above. In this second phase of claims, 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. Our share of the claimed damages in this second round is $6.6 million is based on our ownership percentages described above.

The trial on this second round of claims began October 11, 2011. The DOE has made post-trial filings to keep the record in the cases open while they continue to review documents produced in discovery in an attempt to provide additional trial testimony on selected issues. The three companies have asked for the trial records to be closed in all cases and for a post-trial briefing schedule to be set.

On Thursday March 1, 2012, an order was issued in response to the DOE's motion to compel additional discovery in the Connecticut Yankee and Maine Yankee portions of the case. The Yankee Atomic evidentiary portion has already been closed. This decision closes discovery on Connecticut Yankee, grants potential but limited additional discovery on privileged documents in the Maine Yankee case, and, provides a post-trial briefing schedule that allows the cases to be ready for decision by early May 2012.

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

TRANSMISSION MATTERS

On September 30, 2011, the Commonwealth of Massachusetts filed a complaint with the FERC pursuant to sections 206 and 306 of the Federal Power Act. The complaint was filed on behalf of various parties, including the DPS, and named various New England transmission owners and ISO-NE. The complainants are seeking an order from the FERC to reduce the 11.14 percent base return on equity used in calculating formula rates for transmission service under the ISO-NE open access transmission tariff to a level of 9.2 percent, claiming that the formula rates are unjust and unreasonable. The complainants further request that the FERC: 1) institute paper hearing procedures to investigate the Base ROE and establish a just and reasonable equity return to be reflected in rates for transmission service provided by the New England transmission owners under the ISO-NE open access transmission tariff; 2) establish the earliest possible refund effective date (i.e., the date of complaint), consistent with FERC policy; and 3) direct ISO-NE to make refunds reflecting the difference between transmission rates reflecting an 11.14 percent Base ROE and rates reflecting a just and reasonable Base ROE. We are unable to predict the outcome of this matter at this time or the potential impact on our financial statements.

RECENT ENERGY POLICY INITIATIVES

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

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

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

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

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

The 2011 Legislature expanded the size of allowable "net metering projects" from 250 kilowatts to 500 kilowatts, allowed a utility to have twice as much of that type of power in its portfolio as before, and set a premium price for net-metered solar projects. Net metered customers will be allowed to offset credits against all customer charges, and not simply energy charges.

The 2011 Legislature also instructed the DPS to update the state's energy plan, and, in doing so, to recommend whether Vermont's SPEED law should be replaced by a more traditional Renewable Portfolio Standard. In September 2011, the DPS issued a *Public Review DRAFT 2011* of the Comprehensive Energy Plan for review and comment, and a final plan was issued in December 2011. The plan addresses Vermont's energy future for electricity, thermal energy, transportation, and land use.

Under the plan, which was updated based on public input, the state intends to set Vermont on a path to obtain 90 percent of its energy in all energy sectors from renewable sources by mid-century. This goal is based on a state desire to virtually eliminate Vermont's reliance on oil by mid-century "by moving toward enhanced efficiency measures, greater use of clean, renewable sources for electricity, heating, and transportation, and electric vehicle adoption, while increasing our use of natural gas and biofuel blends where nonrenewable fuels remain necessary." The plan generated significant public comment.

In a separate process, also as required by the 2011 Legislature, the PSB recently issued its "Study on Renewable Energy Requirements." In that report, the PSB recommends that, by 2033, 1) 10 percent of Vermont's overall electric portfolio be met with new small-scale renewable distributed generation; 2) 40 percent of Vermont's overall electric portfolio be met through existing renewable electricity; and 3) 25 percent of Vermont's overall load be met through new renewable energy, and that utilities be required to retire renewable energy credits starting in 2014.

The current Legislature is considering these matters, including the issues of whether Vermont's SPEED law should be amended, whether the standard offer should be expanded and whether Vermont should adopt a more traditional Renewable Portfolio Standard policy. We cannot predict the outcome of these deliberations.

ACCOUNTING MATTERS AND TECHNICAL DEVELOPMENTS

Critical accounting policies and estimates Our financial statements are prepared in accordance with U.S. GAAP, requiring us to make estimates and judgments that affect reported amounts of assets and liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements. Our critical accounting policies and estimates are described in Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K for the year ended December 31, 2011. Also, see Note 2 - Summary of Significant Accounting Policies to the accompanying Notes to Consolidated Financial Statements.

FASB – IASB Convergence The FASB and IASB are working on joint projects to bring U.S. GAAP closer to IFRS, resulting in a major overhaul and reshaping of U.S. GAAP. The FASB's project plan anticipates the completion of some projects in 2011. We have not yet evaluated the impact, if any, that the adoption of the new standards may have on our consolidated financial statements.

On February 24, 2010, the SEC issued a statement of its position regarding global accounting standards. Among other things, the SEC stated that it has directed its staff to execute a work plan, which will include consideration of IFRS as it exists today and after the completion of various convergence projects currently under way between U.S. and international accounting standards-setters. If the SEC determines to move forward with IFRS, the first time that U.S. companies would report under such a system would be no earlier than 2015. Since we are an accelerated filer, we would be required to adopt IFRS in 2016.

Dodd-Frank Act On July 21, 2010, the Dodd-Frank Act was signed into law. While the Dodd-Frank Act has broad implications to the financial services industry, there are some new mandates for public companies that may require changes in corporate governance, compensation, government regulation of the over-the-counter derivatives market, accounting and other areas. The Dodd-Frank Act requires entities to clear most over-the-counter derivatives through regulated central clearing organizations and to trade the derivatives on regulated exchanges.

Since 2010, the SEC, Commodity Futures Trading Commission ("CFTC") and the Federal Reserve have issued many proposed rules designed to carry out the mandates contained in the Dodd-Frank Act. The primary regulator for non-banks will be the CFTC. A few of the rules have become final, but most are expected to be finalized in the middle of 2012, or later.

We have already implemented changes related to non-binding shareholder advisory votes on executive compensation and compensation and benefit plan risk assessments. We are uncertain to what degree this legislation may affect our business in the future, but we are evaluating these additional regulatory requirements and the potential impact on our financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

We consider our most significant market-related risks to be associated with wholesale power markets, equity markets and interest rates. 2008 was a challenging year in the financial markets with record low market returns and extraordinary volatility. Capital markets began to stabilize and trend toward more normal performance in the second half of 2009 and throughout 2010, but volatility returned in 2011. Further decreases in the values of the assets in our pension, postretirement medical and nuclear decommissioning trust funds could increase our future cash outflows related to trust fund contributions. Fair and adequate rate relief through cost-based rate regulation can limit our exposure to market volatility. Below is a discussion of the primary market-related risks associated with our business.

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

Interest Rate Risk: Interest rate changes could impact the value of the debt securities in our pension and postretirement medical benefit trust funds and the valuations of estimated pension and other benefit liabilities, affecting pension and other benefit expenses, contributions to the external trust funds and ultimately our ability to meet future pension and postretirement benefit obligations. We have adopted a diversified investment policy with a goal to mitigate these market impacts. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, and Part II, Item 8, Note 16 - Pension and Postretirement Medical Benefits.

Interest rate changes could also impact the value of the debt securities in our Millstone Unit #3 decommissioning trust and in our Rabbi Trust. At December 31, 2011, the decommissioning trust held debt securities in the amount of $1.4 million and the Rabbi Trust held debt securities in the amount of $2.5 million.

As of December 31, 2011, we had $10.8 million of Industrial Development Revenue bonds outstanding, which have an interest rate that resets monthly. The interest rate on amounts borrowed at year end under our $40 million credit facility resets daily. All other utility debt has a fixed rate. There are no interest rate locks or swap agreements in place.

The table below provides information about interest rates on our long-term debt. The expected variable rates are based on rates in effect at December 31, 2011 (dollars in millions).

	Expected Maturity Date						
	2012	2013	2014	2015	2016	Thereafter	Total
Fixed Rate ($)	$13.64	$13.64	$13.64	$13.64	$13.64	$146.50	$214.70
Average Fixed Interest Rate (%)	6.27%	6.27%	6.27%	6.27%	6.27%	6.47%	
Variable Rate ($)	$0.21	$0.21	$0.17	$0.00	$0.00	$0.00	$0.59
Average Variable Rate (%)	0.90%	0.92%	1.02%	0.20%	n/a	n/a	

Equity Market Risk: As of December 31, 2011, our pension trust held marketable equity securities in the amount of $41.7 million, our postretirement medical trust funds held marketable equity securities in the amount of $11.2 million, our Millstone Unit #3 decommissioning trust held marketable equity securities of $4.4 million and our Rabbi Trust held variable life insurance policies with underlying marketable equity securities of $2.6 million. In 2011, these equity investments experienced negative performance, except the Millstone Unit #3 decommissioning trust experienced positive performance. We experienced positive performance in 2010 and 2009. Also see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, and Part II, Item 8, Note 16 - Pension and Postretirement Medical Benefits for additional information.

Wholesale Power Market Price Risk Our most significant power supply contracts are with Hydro-Québec and VYNPC. Combined, these contracts provide the majority of our total MWh purchases. The contracts are described in more detail in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters and Part II, Item 8, Note 18 - Commitments and Contingencies. Summarized information regarding power purchases under these contracts follows.

		2011		2010		2009	
	Expires	**MWh**	**$/MWh**	MWh	$/MWh	MWh	$/MWh
Hydro-Quebec (a)	2016	922,901	$67.11	963,027	$65.39	919,764	$68.60
VYNPC (b)	2012	1,420,705	$43.92	1,384,551	$42.41	1,551,925	$41.25

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

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

Currently, our power forecast shows energy purchase and production amounts in excess of our load requirements through 2012. Because of this projected power surplus, we enter into forward sale transactions from time to time to reduce price volatility of our net power costs. The effect of increases or decreases in average wholesale power market prices is highly dependent on whether our net power resources at the time are sufficient to meet load requirements. If they are not sufficient to meet load requirements, such as when power from Vermont Yankee is not available as expected, we are in a purchase position. In that case, increased wholesale power market prices would increase our net power costs. If our net power resources are sufficient to meet load requirements, we are in a sale position. In that case, increased wholesale power market prices would decrease our net power costs. The PCAM within our alternative regulation plan allows more timely recovery of our power costs.

We account for some of our power contracts as derivatives under FASB's guidance for derivatives and hedging. Additional information regarding derivatives is presented in Part II, Note 6, Fair Value and Part II, Note 15, Power-Related Derivatives. Summarized information related to the fair value of power contract derivatives is shown in the table below (dollars in thousands):

	Forward Energy Contracts	Financial Transmission Rights	Total
Total fair value at December 31, 2010	$0	$28	$28
Gains and losses (realized and unrealized)			
Included in earnings	(619)	(40)	(659)
Included in Regulatory and other assets/liabilities	(4,940)	0	(4,940)
Purchases	0	24	24
Net Settlements	619	(8)	611
Total fair value at December 31, 2011	($4,940)	$4	($4,936)
Estimated fair value at December 31, 2011 for changes in projected market price:			
10 percent increase	($2,869)	$4	($2,865)
10 percent decrease	($7,010)	$3	($7,007)

We record gains and losses on power-related derivatives and non-derivative power contracts in purchased power and wholesale sales. The PCAM allows us to recover most of our net power costs from customers. Pursuant to a PSB-approved Accounting Order, changes in fair value of all power-related derivatives are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the change in fair value is an unrealized loss or unrealized gain, with an offsetting amount recorded as a decrease or increase in the related derivative asset or liability. As a result of the Accounting Order and the PCAM, changes in market prices would not have a material impact to our future financial results.

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements based on our audits. We did not audit the financial statements of Vermont Transco LLC ("Transco") and Vermont Electric Power Company, Inc. ("Velco") as of December 31, 2010 and for the two years then ended, the Company's investments in which are accounted for by use of the equity method. The Company's equity of $168,500,000 and $126,742,000 in Transco's and Velco's net assets as of December 31, 2010 and 2009, respectively, and of $20,795,000 and $17,124,000 in Transco's and Velco's net income for each of the two years in the period ended December 31, 2010, are included in the accompanying consolidated financial statements. Those financial statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Transco and Velco, is based solely on the reports of other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of Central Vermont Public Service Corporation and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 14, 2012

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

	For the Years ended December 31		
	2011	2010	2009
Operating Revenues	**$359,734**	$341,925	$342,098
Operating Expenses			
Purchased Power - affiliates	**63,798**	60,094	65,329
Purchased Power	**93,161**	100,680	92,653
Production	**10,942**	11,752	11,374
Transmission - affiliates	**11,151**	(3,788)	8,002
Transmission - other	**27,012**	26,652	23,799
Other operation	**56,859**	56,642	59,160
Maintenance	**37,471**	29,851	24,212
Depreciation	**19,306**	17,570	16,921
Taxes other than income	**18,514**	17,472	16,727
Income tax expense	**5,167**	7,545	5,033
Total Operating Expenses	**343,381**	324,470	323,210
Utility Operating Income	**16,353**	17,455	18,888
Other Income			
Equity in earnings of affiliates	**27,733**	21,098	17,472
Allowance for equity funds during construction	**118**	119	161
Other income	**2,794**	3,243	2,935
Other deductions	**(3,021)**	(2,284)	(1,585)
Merger-related expenses	**(25,977)**	0	0
Income tax benefit (expense)	**1,356**	(7,117)	(5,640)
Total Other Income	**3,003**	15,059	13,343
Interest Expense			
Interest on long-term debt	**13,305**	11,163	11,139
Other interest	**479**	458	449
Allowance for borrowed funds during construction	**(132)**	(61)	(106)
Total Interest Expense	**13,652**	11,560	11,482
Net Income	**5,704**	20,954	20,749
Dividends declared on preferred stock	**368**	368	368
Earnings available for common stock	**$5,336**	$20,586	$20,381
Per Common Share Data:			
Basic earnings per share	**$0.40**	$1.66	$1.75
Diluted earnings per share	**$0.40**	$1.66	$1.74
Average shares of common stock outstanding - basic	**13,404,909**	12,370,486	11,660,170
Average shares of common stock outstanding - diluted	**13,487,608**	12,405,866	11,705,518
Dividends declared per share of common stock	**$0.92**	$0.92	$0.92

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

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

	For the Years ended December 31		
	2011	2010	2009
Net Income	**$5,704**	$20,954	$20,749
Other comprehensive income, net of tax:			
Defined benefit pension and postretirement medical plans:			
Portion reclassified through amortizations, included in benefit costs and recognized in net income:			
Actuarial losses, net of income taxes of $65 in 2011, $1 in 2010 and $2 in 2009	**96**	2	3
Prior service cost, net of income taxes of $(1) in 2011, $(1) in 2010 and $9 in 2009	**(2)**	(2)	14
Change in funded status of pension, postretirement medical and other benefit plans, net of income taxes of $(33) in 2011, $(16) in 2010 and $2 in 2009	**(48)**	(23)	2
Comprehensive income adjustments	**46**	(23)	19
Total comprehensive income	**$5,750**	$20,931	$20,768

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	For the Years ended December 31		
Cash flows provided by:	**2011**	2010	2009
OPERATING ACTIVITIES			
Net Income	**$5,704**	$20,954	$20,749
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of affiliates	**(27,733)**	(21,098)	(17,472)
Distributions received from affiliates	**19,385**	14,235	10,695
Depreciation	**19,306**	17,570	16,921
Deferred income taxes and investment tax credits	**10,020**	20,322	9,633
Amortization of capital leases	**946**	991	946
Regulatory and other deferrals and amortization	**(4,802)**	(3,523)	(797)
Non-cash employee benefit plan costs	**6,375**	6,423	6,275
Other non-cash expense and (income), net	**(140)**	5,163	5,225
Changes in assets and liabilities:			
Fortis termination fee reimbursement from Gaz Métro	**19,500**	0	0
Increase in accounts receivable and unbilled revenues	**(1,386)**	(4,949)	(6,520)
(Decrease) increase in accounts payable	**(38)**	(1,728)	4,979
Increase (decrease) in accounts payable - affiliates	**3,299**	(206)	702
Decrease (increase) in other current assets	**1,422**	(916)	4,409
(Increase) decrease in special deposits and restricted cash	**(1,107)**	5,370	(1,734)
Employee benefit plan funding	**(7,705)**	(6,493)	(7,122)
Increase (decrease) in other current liabilities	**5,395**	(867)	(4,986)
Increase (decrease) in other long-term assets	**(4,524)**	640	132
Increase in other long-term liabilities and other	**1,796**	1,639	7
Net cash provided by operating activities	**45,713**	53,527	42,042
INVESTING ACTIVITIES			
Construction and plant expenditures	**(41,129)**	(33,021)	(31,413)
Investment in affiliates (Transco)	**0**	(34,918)	(20,843)
Acquisition of utility property (Vermont Marble and Readsboro)	**(30,159)**	0	0
Increase in restricted cash - project fund investments	**0**	(29,767)	0
Reimbursements of restricted cash - bond proceeds	**17,465**	6,288	0
Project reimbursement from DOE	**1,130**	791	0
Investments in available-for-sale securities	**(1,801)**	(1,624)	(3,761)
Proceeds from sale of available-for-sale securities	**1,555**	1,337	3,436
Other investing activities	**(462)**	(491)	(350)
Net cash used for investing activities	**(53,401)**	(91,405)	(52,931)
FINANCING ACTIVITIES			
Net proceeds from the issuance of common stock	**2,110**	31,942	1,655
Decrease in special deposits for preferred stock mandatory redemption	**0**	1,000	0
Retirement of preferred stock subject to mandatory redemption	**0**	(1,000)	(1,000)
Common and preferred dividends paid	**(12,694)**	(11,712)	(11,088)
Proceeds from revolving credit facility and other short-term borrowings	**100,640**	128,113	48,501
Repayments under revolving credit facility and other short-term borrowings	**(102,057)**	(137,729)	(25,190)
Proceeds from long-term debt	**40,000**	29,767	0
Repayment of long-term debt	**(20,000)**	0	(5,450)
Common stock offering and debt issue costs	**(225)**	(879)	(210)
Reduction in capital lease and other financing activities	**(1,028)**	(1,017)	(982)
Net cash provided by financing activities	**6,746**	38,485	6,236
Net change in cash and cash equivalents	**(942)**	607	(4,653)
Cash and cash equivalents at beginning of the period	**2,676**	2,069	6,722
Cash and cash equivalents at end of the period	**$1,734**	$2,676	$2,069

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

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

	December 31, 2011	December 31, 2010
ASSETS		
Utility plant		
Utility plant	$684,509	$611,746
Less accumulated depreciation	297,441	266,649
Utility plant, net of accumulated depreciation	387,068	345,097
Property under capital leases, net	3,395	4,425
Construction work-in-progress	23,376	20,234
Nuclear fuel, net	2,749	1,737
Total utility plant, net	416,588	371,493
Investments and other assets		
Investments in affiliates	179,974	171,514
Non-utility property, less accumulated depreciation ($3,190 in 2011 and $3,164 in 2010)	2,280	2,196
Millstone decommissioning trust fund	5,950	5,742
Restricted cash	2,550	17,581
Other	7,063	7,013
Total investments and other assets	197,817	204,046
Current assets		
Cash and cash equivalents	1,734	2,676
Restricted cash	4,619	5,903
Special deposits	5	6
Accounts receivable, less allowance for uncollectible accounts ($3,305 in 2011 and $2,649 in 2010)	26,984	28,552
Accounts receivable - affiliates, less allowance for uncollectible accounts	650	314
Unbilled revenues	21,638	21,003
Materials and supplies, at average cost	7,537	7,159
Prepayments	13,966	15,862
Deferred income taxes	11,862	4,501
Power-related derivatives	4	28
Regulatory assets	2,605	1,924
Other deferred charges – regulatory	9,202	2,078
Other deferred charges and other assets	1,533	0
Other current assets	2,289	1,114
Total current assets	104,628	91,120
Deferred charges and other assets		
Regulatory assets	46,381	38,552
Other deferred charges – regulatory	4,623	2,260
Other deferred charges and other assets	6,228	3,275
Total deferred charges and other assets	57,232	44,087
TOTAL ASSETS	$776,265	$710,746

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

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

	December 31, 2011	December 31, 2010
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 15,602,091 issued and 13,473,018 outstanding at December 31, 2011 and 15,470,217 issued and 13,341,144 outstanding at December 31, 2010	**$93,613**	$92,821
Other paid-in capital	**96,040**	94,462
Accumulated other comprehensive loss	**(186)**	(232)
Treasury stock, at cost, 2,129,073 shares at December 31, 2011 and 2010	**(48,436)**	(48,436)
Retained earnings	**127,123**	134,113
Total common stock equity	**268,154**	272,728
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Long-term debt	**240,578**	188,300
Capital lease obligations	**2,471**	3,471
Total capitalization	**519,257**	472,553
Current liabilities		
Current portion of long-term debt	**0**	20,000
Accounts payable	**7,157**	8,137
Accounts payable – affiliates	**15,133**	11,835
Notes payable	**0**	13,695
Nuclear decommissioning costs	**1,433**	1,438
Power-related derivatives	**4,940**	0
Other deferred credits – regulatory	**1,047**	1,108
Other current liabilities	**49,369**	30,763
Total current liabilities	**79,079**	86,976
Deferred credits and other liabilities		
Deferred income taxes	**100,314**	82,406
Deferred investment tax credits	**2,132**	2,387
Nuclear decommissioning costs	**3,827**	5,383
Asset retirement obligations	**3,806**	3,609
Accrued pension and benefit obligations	**40,981**	32,441
Other deferred credits – regulatory	**3,081**	3,886
Other deferred credits and other liabilities	**23,788**	21,105
Total deferred credits and other liabilities	**177,929**	151,217
Commitments and contingencies (Note 18)		
TOTAL CAPITALIZATION AND LIABILITIES	**$776,265**	$710,746

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

CONSOLIDATED STATEMENT OF CHANGES IN COMMON STOCK EQUITY

(in thousands, except share data)

	Common Stock		Treasury Stock			Accumulated		
	Shares Issued	Amount	Shares	Amount	Other Paid-in Capital	Other Comprehensive Loss	Retained Earnings	Total
Balance, December 31, 2008	**13,750,717**	**$82,504**	**(2,175,892)**	**($49,501)**	**$71,489**	**($228)**	**$115,215**	**$219,479**
Net income							20,749	20,749
Other comprehensive income, net of tax						19		19
Common stock issuance costs					(179)			(179)
Dividend reinvestment plan	19,468	117	46,819	1,065	255			1,437
Stock options exercised	36,160	217			284			501
Share-based compensation:								
Common & nonvested shares	4,530	27			58			85
Performance share plans	25,093	151			417			568
Dividends declared:								
Common - $0.92 per share							(10,720)	(10,720)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					16			16
Gain (loss) on capital stock					(161)		(3)	(164)
Balance, December 31, 2009	**13,835,968**	**$83,016**	**(2,129,073)**	**($48,436)**	**$72,179**	**($209)**	**$124,873**	**$231,423**
Net income							20,954	20,954
Other comprehensive income, net of tax						(23)		(23)
Common stock issuance, net of issuance costs	1,498,745	8,992			20,621			29,613
Dividend reinvestment plan	69,234	415			972			1,387
Stock options exercised	45,300	272			432			704
Share-based compensation:								
Common & nonvested shares	5,849	35			88			123
Performance share plans	15,121	91			152			243
Dividends declared:								
Common - $0.92 per share							(11,344)	(11,344)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					16			16
Gain (loss) on capital stock					2		(2)	0
Balance, December 31, 2010	**15,470,217**	**$92,821**	**(2,129,073)**	**($48,436)**	**$94,462**	**($232)**	**$134,113**	**$272,728**
Net income							5,704	5,704
Other comprehensive income, net of tax						46		46
Dividend reinvestment plan	44,801	269			941			1,210
Stock options exercised	50,677	304			596			900
Share-based compensation:								
Common & nonvested shares	8,627	52			317			369
Performance share plans	27,769	167			(292)			(125)
Dividends declared:								
Common - $0.92 per share							(12,326)	(12,326)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					16			16
Balance, December 31, 2011	**15,602,091**	**$93,613**	**(2,129,073)**	**($48,436)**	**$96,040**	**($186)**	**$127,123**	**$268,154**

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS ORGANIZATION

General Description of Business Central Vermont Public Service Corporation ("we", "us", "CVPS" or the "company") is the largest electric utility in Vermont. We engage principally in the purchase, production, transmission, distribution and sale of electricity. We serve approximately 160,000 customers in 163 of the towns and cities in Vermont. Our Vermont utility operation is our core business. We typically generate most of our revenues through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-NE, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue generated from these sales helps to mitigate our power supply costs.

Our wholly owned subsidiaries include C.V. Realty, Inc., East Barnet and CRC. We have equity ownership interests in VYNPC, VELCO, Transco, Maine Yankee, Connecticut Yankee and Yankee Atomic.

Pending Merger with Gaz Métro On July 11, 2011, CVPS, Gaz Métro Limited Partnership ("Gaz Métro") and Danaus Vermont Corp., an indirect wholly owned subsidiary of Gaz Métro ("Merger Sub"), entered into an Agreement and Plan of Merger (the "Merger Agreement").

Upon the terms and subject to the conditions set forth in the Merger Agreement, unanimously approved by the boards of directors of CVPS and Gaz Métro Inc., the general partner of Gaz Métro, Merger Sub will merge with and into CVPS (the "Merger"), with CVPS continuing as the surviving corporation and an indirect wholly owned subsidiary of Gaz Métro.

Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of CVPS common stock (other than shares which are held by any wholly owned subsidiary of the Company or in the treasury of the Company or which are held by Gaz Métro or Merger Sub, or any of their respective wholly owned subsidiaries, all of which shall cease to be outstanding and shall be canceled and none of which shall receive any payment with respect thereto, and dissenting shares) will automatically be converted into the right to receive in cash, without interest, $35.25 per share (the "Merger Consideration"), less any applicable withholding taxes.

Completion of the Merger is subject to various customary conditions. They include, among others, approval by CVPS shareholders; expiration or termination of the applicable Hart-Scott-Rodino Act waiting period; receipt of all required regulatory approvals from, among others, the FERC and the PSB; and the absence of any governmental action challenging or seeking prohibition of the Merger; and the absence of any material adverse effect with respect to CVPS. Each party's obligation to consummate the Merger is also subject to additional customary conditions including, subject to certain exceptions, the accuracy of the representations and warranties of the other party and performance in all material respects by the other party of its obligations.

The Merger Agreement contains certain termination rights for both CVPS and Gaz Métro and further provides that upon termination of the merger agreement under specified circumstances, CVPS may be required to reimburse Gaz Métro the amount of $19.5 million paid to CVPS by Gaz Métro to reimburse CVPS for a termination payment to FortisUS, Inc. in connection with the termination of a prior merger agreement between CVPS and FortisUS, Inc. A party desiring to terminate must provide written notice of termination to the other party. A notice of termination may be provided at any time after July 11, 2012, if regulatory approval has been obtained at that time but the transaction has not closed in accordance with the Agreement, or January 11, 2013, if regulatory approval has not been obtained by the 12-month anniversary of the Merger Agreement and the transaction has not closed by the 18-month anniversary.

Regulatory Approvals: On September 2, 2011, CVPS, Danaus Vermont Corp., Northern New England Energy Corporation, for itself and as agent for Gaz Métro and the direct and indirect upstream parents of Gaz Métro, GMP, and Vermont Low Income Trust for Electricity, Inc. filed a petition with the PSB for approval of the proposed merger announced by the companies on July 12, 2011. The PSB established a review schedule, beginning with a workshop held on October 14, 2011 and a public hearing on November 1, 2011. Written testimony and discovery responses have been filed with the PSB and technical hearings are scheduled to begin on March 21, 2012 and are currently expected to end on or before April 4, 2012. The hearing schedule may be delayed or extended, at the discretion of the PSB, and there exists no time limit within which the PSB must issue its decision whether to approve the merger.

In addition, we made other regulatory filings seeking approval of the Merger, including with the NRC, the FERC, the Federal Trade Commission, Federal Communications Commission, the Committee on Foreign Investments in the U.S., New York State Public Service Commission, New Hampshire Public Utilities Commission, and the Maine Public Utility Commission. On September 26, 2011, in connection with the Hart Scott-Rodino filing, the Federal Trade Commission granted early termination of the statutory waiting period, which effectively allows us to continue planning for the Merger. On November 22, 2011 we received approvals from the Committee on Foreign Investments in the U.S. and the Maine Public Utility Commission. Also, on November 22, 2011 the New York State Public Service Commission issued a declaratory ruling of no jurisdiction. On March 6, 2012, we received approval from the FERC and on March 7, 2012, we received approval from the Federal Communications Commission for the transfer of control of our radio licenses.

Shareholder Approval: On September 29, 2011, CVPS held a Special Meeting of Shareholders ("Special Meeting"), in Rutland, Vermont. At the meeting, the shareholders approved the Agreement and Plan of Merger, effective as of July 11, 2011, and in a non-binding advisory vote approved the change-in-control payments related to the Merger. Over 75 percent of the outstanding shares of the company were represented at the meeting, and of those, more than 97 percent voted in support of the sale.

Reimbursement of Termination Fee: On September 29, 2011, as a result of the approval by the company's shareholders of the Merger, Gaz Métro reimbursed CVPS for the full amount of the Fortis Termination Payment of $17.5 million plus expenses of FortisUS Inc. of $2 million. Such reimbursement was required pursuant to the terms of CVPS's Merger Agreement with Gaz Métro.

Under the Merger Agreement, CVPS is required to repay the amount of such reimbursement to Gaz Métro in the event the Merger Agreement is terminated because of either the issuance of an order or injunction prohibiting the Merger (other than as a result of the action by a governmental entity with respect to required regulatory approvals) or the breach by CVPS of its representations, warranties or covenants contained in the Merger Agreement. If the Merger Agreement is terminated for any other reason, CVPS is not required to repay such amount to Gaz Métro. While CVPS believes it is unlikely that the Merger Agreement will be terminated on a basis giving rise to a requirement to repay Gaz Métro and, accordingly, believes that the likelihood of such repayment is remote, the final accounting for the reimbursement cannot be determined until the Merger is either completed or terminated. Accordingly, the reimbursement has been recorded as an Other Current Liability until that time.

Terminated Merger Agreement with Fortis On May 27, 2011, CVPS, FortisUS Inc., Cedar Acquisition Sub Inc., a direct wholly owned subsidiary of Fortis ("Merger Sub") and Fortis Inc., the ultimate parent of Fortis ("Ultimate Parent"), entered into an Agreement and Plan of Merger (the "Fortis Merger Agreement").

On July 11, 2011, prior to entering into the Merger Agreement with Gaz Métro, CVPS terminated the Fortis Merger Agreement. In accordance with the Fortis Merger Agreement, on July 12, 2011, CVPS paid FortisUS Inc. $19.5 million (the "Fortis Termination Payment"), consisting of a termination fee of $17.5 million and expenses of FortisUS Inc. of $2 million. These amounts have been recorded as a component of Other Income on the Consolidated Statement of Income in 2011. The Merger Agreement with Gaz Métro required Gaz Métro to reimburse CVPS for its payment of the Fortis Termination Payment immediately following the approval of the Merger Agreement by CVPS shareholders. It also provides that CVPS will be required to pay Gaz Métro the full amount of the Fortis Termination Payment reimbursement if the Merger Agreement is terminated under certain circumstances.

Vendor claim: In June 2011, following our announcement of the Fortis Merger Agreement, we received notice of a claim for up to $4.8 million from a former financial advisor, related to the pending merger. We have assessed the claim and do not believe that any amount is owed. In order to resolve the dispute, on December 23, 2011, we filed a declaratory judgment action in the United States District Court for the District of Vermont, seeking a declaration that we do not owe any amount to the vendor.

Litigation Related to Merger Agreement On or about June 2, 2011, a lawsuit captioned *David Raul v. Lawrence Reilly, et al.*, Civil Division Docket No. 377-6-11-RDCV, was filed in the Superior Court of Vermont, Rutland Unit against CVPS and members of the CVPS Board of Directors. The lawsuit also named as defendants FortisUS Inc. and one of its affiliates. The *Raul* complaint, which purported to be brought on behalf of a class consisting of the public stockholders of CVPS, alleged that CVPS's directors breached their fiduciary duties by entering into the Fortis Merger Agreement for a price that is alleged to be unfair, as the result of a process alleged to be unfair and inadequate, with material conflicts of interest and so as to benefit themselves, and including no-solicitation, matching rights and termination fee provisions alleged to be designed to ensure that no competing offers would emerge for CVPS. The *Raul* complaint also included a claim of aiding and abetting against CVPS and the Fortis entities. The *Raul* complaint sought, among other things, injunctive relief against the proposed transaction with Fortis as well as other equitable relief, damages and attorneys' fees and costs. On June 23, 2011, following the announcement of an offer received from Gaz Métro, David Raul filed an amended class action complaint repeating his earlier allegations and claims but also referring to this development and claiming that the CVPS Board should terminate the Fortis Merger Agreement and negotiate a new deal with Gaz Métro.

On or about June 17, 2011 and June 20, 2011, two additional complaints (Civil Division Docket Nos. 417-6-11-RDCV and 425-6-11-RDCV, respectively) were filed in the Superior Court of Vermont, Rutland Unit, containing claims and allegations similar to those in the original *Raul* complaint and seeking similar relief on behalf of the same putative class. These complaints were filed, respectively, by *IBEW* Local 98 Pension Fund and by Adrienne Halberstam, Jacob Halberstam and Sarah Halberstam.

On July 13, 2011, a lawsuit captioned *Howard Davis v. Central Vermont Public Service, et al.*, Case No. 5:11-CV-181 was filed in the United States District Court for the District of Vermont against CVPS and members of the CVPS Board of Directors. The lawsuit also named as defendants Gaz Métro Limited Partnership and one of its affiliates. The *Davis* complaint, which purported to be brought on behalf of a class consisting of the public stockholders of CVPS, alleged that CVPS's directors breached their fiduciary duties by, among other things, allegedly failing to undertake an adequate sales process prior to the Fortis Merger Agreement, entering into the Merger Agreement with Gaz Métro at an unfair price and pursuant to an unfair process, engaging in self-dealing, and by including various "deal protection devices" in the Merger Agreement. The *Davis* complaint also included a claim for aiding and abetting against CVPS and the Gaz Métro entities. The *Davis* complaint sought injunctive relief and other equitable relief against the proposed transaction with Gaz Métro, as well as attorneys' fees and costs.

On July 22, 2011, the Halberstam plaintiffs in the state case filed an amended complaint in the Vermont Superior Court, Rutland Unit, which added Gaz Métro Limited Partnership and one of its affiliates as defendants in addition to the defendants named in the original complaint. The amended complaint contained claims and allegations similar to those in the *Davis* complaint and sought similar relief.

On August 2, 2011, an Amended Class Action Complaint was filed in the *Davis* action reiterating the previous claims of breaches of fiduciary duty and adding claims that the Company's proxy materials regarding the Merger are materially misleading and/or incomplete in various respects, in alleged violation of fiduciary duties and the federal securities laws. The Amended Class Action Complaint in the *Davis* action seeks injunctive and other equitable relief against the proposed transaction with Gaz Métro, damages, and attorneys' fees and costs.

On or about August 17, 2011, the three cases pending in the Superior Court of Vermont were consolidated by court order, in accordance with a stipulation that had been filed by the parties. The court also entered orders stating that defendants need only respond to a consolidated amended complaint to be filed, denying a motion for expedited discovery that had been brought by the plaintiffs, and staying all discovery until the legal sufficiency of a consolidated amended complaint could be determined.

On August 23, 2011, *IBEW* moved for leave to file a consolidated amended complaint in the state court proceedings. The proposed consolidated amended complaint contained claims for breach of fiduciary duty against the members of the CVPS Board of Directors in connection with both the Fortis Merger Agreement and the subsequent Gaz Métro Merger Agreement, including claims that the proxy materials provided in connection with the proposed shareholder vote on the Merger were misleading and/or incomplete, and that the CVPS Board had violated its fiduciary duties. The proposed consolidated amended complaint also contained claims for aiding and abetting fiduciary breaches against CVPS and Gaz Métro. The proposed consolidated amended complaint sought, among other relief, an injunction against consummation of the Gaz Métro Merger and damages, including but not limited to damages allegedly resulting from CVPS's payment of a termination fee in connection with the termination of the Fortis Merger Agreement.

On September 1, 2011, plaintiff in the *Davis* action filed a motion seeking a preliminary injunction against the September 29, 2011 shareholder vote that was scheduled in connection with the Merger. On September 16, 2011, defendants in the *Davis* action filed motions to dismiss the Amended Class Action Complaint.

On September 19, 2011, CVPS and the other defendants in the *Davis* action entered into a memorandum of understanding with the *Davis* plaintiff regarding an agreed in principle class-wide settlement of the *Davis* action, subject to court approval. In the memorandum of understanding, the parties agreed that CVPS would make certain disclosures to its shareholders relating to the Merger, in addition to the information contained in the initial Proxy Statement, in exchange for a settlement of all claims. Pursuant to the memorandum of understanding, CVPS subsequently issued a Supplemental Proxy statement that included the additional disclosures. On November 28, 2011, the parties to the *Davis* action entered into a finalized settlement agreement consistent with the terms of the memorandum of understanding, which was then submitted to the court by the *Davis* plaintiff together with a request for preliminary approval. The *IBEW* plaintiff subsequently moved to intervene in the *Davis* lawsuit for the purpose of objecting to the proposed settlement agreement. On December 21, 2011, the court held a hearing on the request for preliminary approval and on the *IBEW's* motion to intervene. The request for preliminary approval was denied without prejudice to refile. The *IBEW* motion to intervene was also denied without prejudice.

Meanwhile, a putative class action complaint captioned *IBEW Local 98 Pension Fund, Adrienne Halberstam, Jacob Halberstam, Sarah Halberstam, and David Raul v. Central Vermont Public Service, et al.*, Case No. 5:11-CV-222 was filed in the United States District Court for the District of Vermont against CVPS, Gaz Métro, and members of the CVPS Board of Directors. This federal *IBEW* complaint, dated September 15, 2011, contained claims of breach of fiduciary duty and inadequate proxy statement disclosures that are substantially similar to those contained in the proposed consolidated amended complaint filed by the same plaintiffs in the Superior Court of Vermont. The federal *IBEW* complaint also included allegations of violations of the Securities Exchange Act of 1934. Defendants filed motions to dismiss and, on December 7, 2011, the federal *IBEW* complaint was amended. The amended complaint contains substantially similar claims and allegations. Defendants have moved to dismiss the *IBEW* amended complaint and briefing on that motion has been completed.

On January 12, 2012, the parties to the state court lawsuits filed a stipulation for dismissal without prejudice of those proceedings. On January 24, 2012, the state court entered an order stating that the state court lawsuits would be dismissed without prejudice unless it received a filed objection by January 31, 2012. No such objection was filed.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation These financial statements have been prepared pursuant to the rules and regulations of the SEC and in accordance with U.S. GAAP. The accompanying consolidated financial statements contain all normal, recurring adjustments considered necessary to present fairly the financial position as of December 31, 2011 and 2010, and the results of operations and cash flows for the years ended December 31, 2011, 2010 and 2009. The results of operations for the interim periods presented herein may not be indicative of the results that may be expected for any other period or the full year. These consolidated financial statements should be read in conjunction with the accompanying notes.

We consider subsequent events or transactions that occur after the balance sheet date, but before the financial statements are issued, to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure.

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

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

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

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

Investments in entities over which we do not maintain a controlling financial interest are accounted for using the equity method when we have the ability to exercise significant influence over their operations. Under this method, we record our ownership share of the net income or loss of each investment in our consolidated financial statements. We have concluded that consolidation of these investments is not required under FASB's consolidation guidance for variable interest entities. See Note 4 - Investments in Affiliates.

Variable Interest Entities The primary beneficiary of a variable interest entity must consolidate the financial statements of that entity. Transco and VYNPC are variable interest entities; however, we are not the primary beneficiary of either of these entities because we do not control the activities that are most relevant to their operating results. Our maximum exposure to loss is the amount of our equity investments in Transco and VYNPC. See Note 4 - Investments in Affiliates.

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

Regulatory Accounting Our utility operations are regulated by the PSB, FERC and the Connecticut Department of Public Utility and Control, with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. As required, we prepare our financial statements in accordance with FASB's guidance for regulated operations. The application of this guidance results in differences in the timing of recognition of certain expenses from those of other businesses and industries. In order for us to report our results under the accounting for regulated operations, our rates must be designed to recover our costs of providing service, and we must be able to collect those rates from customers. If rate recovery of the majority of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, we would reassess whether this accounting standard should continue to apply to our regulated operations. In the event we determine that we no longer meet the criteria for applying the accounting for regulated operations, the accounting impact would be a charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, we believe future recovery of our regulatory assets is probable. Criteria that could give rise to the discontinuance of accounting for regulated operations include increasing competition that restricts a company's ability to establish prices to recover specific costs, and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. See Note 9 - Retail Rates and Regulatory Accounting for additional information.

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

Income Taxes In accordance with FASB's guidance for income tax accounting, we recognize deferred tax assets and liabilities for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the tax rate expected to be in effect when the differences are expected to reverse. Investment tax credits associated with utility plant are deferred and amortized ratably to income over the lives of the related properties. We record a valuation allowance for deferred tax assets if we determine that it is more likely than not that such tax assets will not be realized.

We follow FASB's guidance and methodology for estimating and reporting amounts associated with uncertain tax positions, including interest and penalties.

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

Allowance for Uncollectible Accounts We record allowances for uncollectible accounts based on customer-specific analysis, current assessments of past due balances and economic conditions, and historical experience. Additional allowances for uncollectible accounts may be required if there is deterioration in past due balances, if economic conditions are less favorable than anticipated, or for customer-specific circumstances, such as financial difficulty or bankruptcy. At December 31, 2011, our allowance for uncollectible accounts was $3.3 million, compared to $2.6 million at December 31, 2010.

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

	Balance at beginning of year	Charged to income and expenses		Deductions		Balance at end of year
2011						
Reserve for uncollectible accounts receivable	$2,649	2,624		1,968		$3,305
2010						
Reserve for uncollectible accounts receivable	$3,577	723	(2)	1,651	(1)	$2,649
2009						
Reserve for uncollectible accounts receivable	$2,184	3,179	(2)	1,786	(1)	$3,577

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

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

Valuation of Long-Lived Assets We periodically evaluate the carrying value of long-lived assets, including our investments in nuclear generating companies, our unregulated investments, and our interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from the asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. No impairments of long-lived assets were recorded in 2011, 2010, or 2009.

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

	2011	2010
Wholly owned electric plant in service:		
Distribution	**$331,797**	$319,847
Hydro facilities	**94,832**	50,692
Transmission	**63,474**	57,998
General	**38,626**	36,393
Intangible plant	**12,860**	6,837
Other	**4,952**	4,695
Sub-total wholly owned electric plant in service	**546,541**	476,462
Jointly owned generation and transmission units	**116,001**	115,748
Completed construction	**21,924**	19,493
Held for future use	**43**	43
Utility plant	**684,509**	611,746
Accumulated depreciation	**(297,441)**	(266,649)
Property under capital leases, net	**3,395**	4,425
Construction work-in-progress	**23,376**	20,234
Nuclear fuel, net	**2,749**	1,737
Total Utility Plant, net	**$416,588**	$371,493

Property Under Capital Leases We record our commitments with respect to the Hydro-Québec Phase I and II transmission facilities, and other equipment, as capital leases. At December 31, 2011, Property under Capital Leases was comprised of $24.8 million of original cost less $21.4 million of accumulated amortization. At December 31, 2010, Property under Capital Leases was comprised of $24.9 million of original cost less $20.5 million of accumulated amortization. See Note 18 - Commitments and Contingencies.

Depreciation We use the straight-line remaining life method of depreciation. The total composite depreciation rate was 2.81 percent of the cost of depreciable utility plant in 2011, 2.88 in 2010 and 2.85 percent in 2009.

Allowance for Funds Used During Construction AFUDC is a non-cash item that is included in the cost of utility plant and represents the cost of borrowed and equity funds used to finance construction. Our AFUDC rates were 5 percent in 2011, 7.7 percent in 2010 and 7.8 percent in 2009. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense on the Consolidated Statements of Income. The cost of equity funds is recorded as other income on the Consolidated Statements of Income.

Asset Retirement Obligations Changes to asset retirement obligations follow (dollars in thousands):

	2011	2010
Asset retirement obligations at January 1	**$3,609**	$3,247
Revisions in estimated cash flows	**62**	246
Accretion	**149**	136
Liabilities settled during the period	**(14)**	(20)
Asset retirement obligations at December 31	**$3,806**	$3,609

We have legal retirement obligations for decommissioning related to our joint-owned nuclear plant, Millstone Unit #3, and have an external trust fund dedicated to funding our share of future costs. The year-end aggregate fair value of the trust fund was $5.9 million in 2011 and $5.7 million in 2010, and is included in Investments and Other Assets on the Consolidated Balance Sheets.

Non-legal Removal Costs: Our regulated operations collect removal costs in rates for certain utility plant assets that do not have associated legal asset retirement obligations. Non-legal removal costs of about $12.1 million in 2011 and $11.5 million in 2010 are included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Environmental Liabilities We are engaged in various operations and activities that subject us to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. Our policy is to accrue a liability for those sites where costs for remediation, monitoring and other future activities are probable and can be reasonably estimated. See Note 18 - Commitments and Contingencies.

Derivative Financial Instruments We account for certain power contracts as derivatives under the provisions of FASB's guidance for derivatives and hedging. This guidance requires that derivatives be recorded on the balance sheet at fair value. Derivatives are recorded as current and long-term assets or liabilities depending on the duration of the contracts. Our derivative financial instruments are related to managing our power supply resources to serve our customers, and are not for trading purposes. Contracts that qualify for the normal purchase and sale exception to derivative accounting are not included in derivative assets and liabilities. Additionally, we have not elected hedge accounting for our power-related derivatives.

Based on a PSB-approved accounting order, we record the changes in fair value of all power-related derivative financial instruments as deferred charges or deferred credits on the balance sheet, depending on whether the change in fair value is an unrealized loss or gain. Realized gains and losses on sales are recorded as increases to or reductions of operating revenues, respectively. For purchase contracts, realized gains and losses are recorded as reductions of or additions to purchased power expense, respectively. For additional information about power-related derivatives, see Note 6 - Fair Value and Note 15 - Power-Related Derivatives.

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

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

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the DOE under the ARRA; however, prior to January 1, 2011, the grant reimbursements were not reflected in our current rates. The grant reimbursements were recorded to a regulatory liability. Effective January 1, 2011 grant reimbursements are reflected in our rates.

Fair Value We use a fair value hierarchy to indicate the relative reliability of the fair value measure. The highest priority is given to quoted prices in active markets, and the lowest to unobservable data, such as our internal information. Fair value measurements are applicable to financial instruments that are subject to mark-to-market accounting such as our investments in available-for-sale securities, restricted cash, cash equivalents and derivative contracts. See Note 5 – Financial Instruments and Note 6 – Fair Value.

Share-Based Compensation Share-based compensation costs are measured at the grant date based on the fair value of the award and recognized as expense on a straight-line basis over the requisite service period. See Note 10 - Share-Based Compensation.

Pension and Benefits Our defined benefit pension plans and postretirement welfare benefit plans are accounted for in accordance with FASB's guidance for employee retirement benefits. We use the fair value method to value all asset classes included in our pension and postretirement medical benefit trust funds. See Note 16 - Pension and Postretirement Medical Benefits for more information.

Accumulated Other Comprehensive Loss Accumulated other comprehensive loss on the Consolidated Balance Sheets is related to employee benefits.

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

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

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

	2011	2010	2009
Interest on temporary investments	**$4**	$7	$61
Non-utility revenue and non-operating rental income	**1,761**	1,801	1,862
Amortization of contributions in aid of construction - tax adder	**891**	938	975
Other interest and dividends	**62**	178	16
Gain on sale of non-utility property	**1**	4	2
Miscellaneous other income	**75**	315	19
Total	**$2,794**	$3,243	$2,935

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

	2011	2010	2009
Supplemental retirement benefits and insurance	**$830**	$344	($249)
Non-utility expenses	**1,421**	1,300	1,320
Miscellaneous other deductions	**770**	640	514
Total	**$3,021**	$2,284	$1,585

Merger-related Expenses: The components of Merger-related expenses on the Consolidated Statements of Income for 2011 includes a $19.5 million Fortis termination fee and $6.5 million of other merger-related costs.

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

	2011	2010
Taxes	**$12,550**	$14,662
Insurance	**434**	412
Miscellaneous	**982**	788
Total	**$13,966**	$15,862

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

	2011	2010
Deferred compensation plans and other	$764	$2,596
Accrued employee-related costs	3,244	4,660
Other taxes and Energy Efficiency Utility	4,633	4,105
Cash concentration account - outstanding checks	4,131	2,358
Obligation under capital leases	917	942
Provision for rate refund	390	5,137
Fortis termination reimbursement	19,500	0
Tropical storm Irene expense accrual	1,178	0
Goods received but not invoiced	3,374	2,344
Miscellaneous accruals	11,238	8,621
Total	$49,369	$30,763

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

	2011	2010
Environmental reserve	$0	$505
Non-legal removal costs	12,126	11,531
Contribution in aid of construction - tax adder	3,785	4,245
Reserve for loss on power contract	3,588	4,784
Accrued income taxes and interest	282	0
Provision for rate refund	0	4
VMPD rate phase in	702	0
Deferred compensation	3,265	0
Other	40	36
Total	$23,788	$21,105

Dividends Declared Per Share of Common Stock: The timing of common stock dividend declarations fluctuates whereas the dividend payments are made on a quarterly basis. In 2011, 2010 and 2009, we declared and paid cash dividends of 92 cents per share of common stock.

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

	2011	2010	2009
Interest (net of amounts capitalized)	$13,561	$11,356	$11,614
Net income taxes refunded	($9,148)	($5,703)	($1,244)

Construction and plant expenditures on the Consolidated Statements of Cash Flows reflect actual payments made during the periods. Construction and plant-related expenditures and CVPS SmartPower® reimbursements are accrued at the end of each reporting period. At December 31, 2011, $0.5 million of construction and plant-related accruals was included in Accounts Payable, and $1.6 million was included in Other current liabilities. At December 31, 2010, $1.5 million of construction and plant-related accruals was included in Accounts Payable, and $1.7 million was included in Other Current Liabilities. At December 31, 2011, Accounts Receivable included $0.7 million representing the capital component of CVPS SmartPower® reimbursements not yet received from the DOE, and Other current assets included $0.3 million of estimated DOE capital reimbursements. We reduced Construction work-in-progress during 2011 for these pending reimbursements. At December 31, 2010, Accounts Receivable included $0.3 million representing the capital component of CVPS SmartPower® reimbursements not yet received from the DOE. We reduced Construction work-in-progress during 2010 for this pending reimbursement.

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

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

NOTE 3 - EARNINGS PER SHARE

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

	2011	2010	2009
Numerator for basic and diluted EPS:			
Income from continuing operations	**$5,704**	$20,954	$20,749
Dividends declared on preferred stock	**368**	368	368
Net income from continuing operations available for common stock	**$5,336**	$20,586	$20,381
Denominators for basic and diluted EPS:			
Weighted-average basic shares of common stock outstanding	**13,404,909**	12,370,486	11,660,170
Dilutive effect of stock options	**49,950**	14,388	20,646
Dilutive effect of performance shares	**32,749**	20,992	24,702
Weighted-average diluted shares of common stock outstanding	**13,487,608**	12,405,866	11,705,518

Stock Options: There were no outstanding stock options excluded from the calculation in 2011. Outstanding stock options totaling 44,244 for 2010 and 153,017 for 2009 were excluded from the computation of diluted shares because the exercise prices were below the current average market price of the common shares.

Performance Shares: Based on performance as of December 31, 2011, outstanding performance shares totaling 2,946 were excluded from the computation of diluted shares 2011 because the performance share measures were not met. Outstanding performance shares totaling 37,330 for 2010 and 26,973 for 2009 were excluded from the diluted EPS calculation as either the performance share measures were not met or there was an antidilutive impact as of the end of the year.

NOTE 4 - INVESTMENTS IN AFFILIATES

Our equity method investments and equity in earnings from those investments follow (dollars in thousands):

	Direct Ownership	Investment At December 31 2011	2010	Equity in Earnings As of December 31 2011	2010	2009
Vermont Electric Power Company, Inc.:						
Common stock (a)	47.10%	**$11,928**	$11,875			
Preferred stock (b)	49.19%	**362**	287			
Subtotal		**$12,290**	12,162	**$1,419**	$1,473	$1,776
Vermont Transco LLC (c)	36.59%	**164,726**	156,338	**26,100**	19,322	15,348
Vermont Yankee Nuclear Power Corporation	58.85%	**2,817**	2,875	**212**	293	328
Connecticut Yankee Atomic Power Company	2.00%	**42**	43	**0**	0	13
Maine Yankee Atomic Power Company	2.00%	**43**	41	**2**	14	2
Yankee Atomic Electric Company	3.50%	**56**	55	**0**	(4)	5
Total Investments in Affiliates		**$179,974**	$171,514	**$27,733**	$21,098	$17,472

(a) Ownership percentage was 47.05 percent at December 31, 2010.
(b) Ownership percentage was 48.03 percent at December 31, 2010.
(c) Ownership percentage was 36.68 percent at December 31, 2010.

Undistributed earnings of these affiliates, included in Retained Earnings on our Consolidated Balance Sheets, amounted to $30.5 million at December 31, 2011 and $22.1 million at December 31, 2010. Of these amounts, $29.5 million at December 31, 2011 and $21.2 million at December 31, 2010 were from our investment in Transco.

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

Our ownership interest in VELCO is represented by common and preferred stock. The third quarter 2011 purchases of Readsboro and Vermont Marble increased our ownership percent of VELCO's common and preferred stock. Our ownership interest in VELCO's common stock was 47.10 percent at December 31, 2011 and 47.05 percent at December 31, 2010. Our ownership interest in VELCO's preferred stock was 49.19 percent at December 31, 2011 and 48.03 percent at December 31, 2010.

We did not invest in Transco in 2011 but invested $34.9 million in 2010. The third quarter 2011 purchases of Readsboro and Vermont marble marginally increased our ownership interest. Our direct ownership interest was 36.59 percent at December 31, 2011 and 36.68 percent at December 31, 2010. Our ownership interest in Transco is represented by Class A Units that receive a return on equity investments of 11.5 percent under the 1991 Transmission Agreement ("VTA"). Our total direct and indirect interest in Transco was 40.93 percent at December 31, 2011 and 41.02 percent at December 31, 2010. Transco is a variable interest entity but we are not the primary beneficiary.

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

VELCO's summarized consolidated financial information (including Transco) for the years ended December 31 follows (dollars in thousands):

	2011	2010	2009
Operating revenues	**$136,092**	$104,016	$93,596
Operating income	**$79,269**	$58,544	$51,903
Income before non-controlling interest and income tax	**$62,738**	$50,029	$42,214
Less members' non-controlling interest in income	**58,144**	45,728	36,202
Less income tax	**2,081**	1,056	2,338
Net income	**$2,513**	$3,245	$3,674

	2011	2010
Current assets	**$68,983**	$38,639
Non-current assets	**817,178**	756,346
Total assets	**886,161**	794,985
Less:		
Current liabilities	**127,121**	47,374
Non-current liabilities	**341,571**	345,869
Members' non-controlling interest	**391,933**	375,945
Net assets	**$25,536**	$25,797

Cash dividends received from VELCO were $1.3 million in 2011, 2010 and 2009. Accounts payable to VELCO were $7.3 at December 31, 2011 and $5.8 million at December 31, 2010.

Transco's summarized financial information (included above in VELCO's summarized consolidated financial information) for the years ended December 31 follows (dollars in thousands):

	2011	2010	2009
Operating revenues	**$135,130**	$103,547	$93,085
Operating income	**$80,500**	$59,884	$51,903
Net income	**$64,424**	$51,849	$42,623

	2011	2010
Current assets	**$53,422**	$34,506
Non-current assets	**798,732**	746,351
Total assets	**852,154**	780,857
Less:		
Current liabilities	**102,133**	33,175
Non-current liabilities	**315,456**	330,766
Mandatorily redeemable membership units	**10,000**	10,000
Net assets	**$424,565**	$406,916

Transmission services provided by Transco are billed to us under the VTA. All Vermont electric utilities are parties to the VTA. This agreement requires the Vermont utilities to pay their pro rata share of Transco's total costs, including interest and a fixed rate of return on equity, less the revenue collected under the ISO-NE Open Access Transmission Tariff and other agreements.

Transco's billings to us primarily include the VTA and charges and reimbursements under the NOATT. Included in Transco's operating revenues above are transmission services to us amounting to $11.2 million in 2011, a net credit of $3.8 million in 2010 and $8 million in 2009. These amounts are included in Transmission - affiliates on our Consolidated Statements of Income. Cash dividends received from Transco were $17.8 million in 2011, $12.7 million in 2010 and $9 million in 2009. Accounts payable to Transco were $1.8 million at December 31, 2011. There was no accounts payable due at December 31, 2010. There were no Accounts receivable from Transco at December 31, 2011 and $0.2 million at December 31, 2010.

VYNPC VYNPC sold its nuclear plant to Entergy-Vermont Yankee in July 2002. The sale agreement included a purchased power contract between VYNPC and Entergy-Vermont Yankee. Under the VY PPA, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates and, in turn, bills the VY PPA charges from Entergy-Vermont Yankee with certain residual costs of service through a FERC tariff to the VYNPC sponsors, including us. The residual costs of service include VYNPC's other operating expenses, including any expenses incurred in administering the VY PPA and the power contracts, and an allowed return on equity. Our entitlement to energy produced by the Vermont Yankee plant is about 29 percent. See Note 18 – Commitments and Contingencies, Long-term Power Purchases.

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

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

	2011	2010	2009
Operating revenues	**$179,155**	$168,592	$183,411
Operating income (loss)	**($1,569)**	($2,961)	($2,991)
Net income	**$360**	$497	$557

	2011	2010
Current assets	**$25,376**	$26,844
Non-current assets	**146,408**	145,079
Total assets	**171,784**	171,923
Less:		
Current liabilities	**17,466**	17,317
Non-current liabilities	**149,531**	149,721
Net assets	**$4,787**	$4,885

VYNPC's revenues shown in the table above include sales to us of $62.4 million in 2011, $58.7 million in 2010 and $64 million in 2009. These amounts are included in Purchased power - affiliates on our Consolidated Statements of Income. Accounts payable to VYNPC were $5.9 million at December 31, 2011 and December 31, 2010. Cash dividends received were $0.3 million in 2011, $0.2 million in 2010 and $0.3 million in 2009.

DOE Litigation: VYNPC has been seeking recovery of fuel storage-related costs from the DOE. Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the disposal of spent nuclear fuel and high-level radioactive waste. VYNPC, as required by that Act, signed a contract with the DOE (the "Standard Contract") to provide for the disposal of spent nuclear fuel and high-level radioactive waste from its nuclear generation station beginning no later than January 31, 1998. The Standard Contract obligated VYNPC to pay a one-time fee of approximately $39.3 million for disposal costs for all nuclear fuel used through April 6, 1983 (the "pre-1983 fuel"), and a fee payable quarterly equal to one mil per kilowatt-hour of nuclear generated and sold electricity after April 6, 1983. Except for the obligation to pay the one-time fee and the right to claims relating to the DOE's defaults under the Standard Contract with respect to the pre-1983 fuel, the Standard Contract was assigned to Entergy effective with the sale of the plant in 2002. VYNPC filed its lawsuit against the government for the DOE's breach in the U.S. Court of Federal Claims on July 30, 2002.

Through 2011, VYNPC has accumulated $143 million in an irrevocable trust to be used exclusively for meeting this obligation ($144.7 million including accrued interest) at some future date, provided the DOE complies with the terms of the aforementioned Standard Contract. Under the terms of the sale agreement, VYNPC retained the spent fuel trust fund assets, the related obligation to make this payment to the DOE when and if it becomes due, and its claims against DOE associated with the pre-1983 fuel. VYNPC 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.

On October 22, 2008, the trial judge presiding over VYNPC's case granted a motion for partial summary judgment filed by Entergy, and dismissed VYNPC's case. The judge ruled that VYNPC lacked any actionable claim that was not transferred to Entergy in the sale of the plant. On April 3, 2009, the trial judge reissued his decision to dismiss VYNPC's case under a special rule that would allow VYNPC to immediately appeal the decision to the United States Court of Appeals for the Federal Circuit ("the Federal Circuit"). However, on September 2, 2009, the Federal Circuit remanded the matter to the trial judge with instructions to vacate his most recent ruling. The effect of this action was to suspend VYNPC's appeal until the trial judge issued a final order in the related Entergy proceeding. The order was issued on October 15, 2010, and on December 13, 2010, VYNPC filed a Notice of Appeal to the Court of Appeals for the Federal Circuit.

In its appeal, VYNPC filed a legal brief on May 12, 2011, and it was followed by amicus curiae ("friend of the court") briefs from the state of Vermont on May 19, 2011 and October 24, 2011. Reply briefs were filed by the DOE on December 5, 2011, VYNPC on December 22, 2011, and Entergy Nuclear-Vermont Yankee on January 4, 2012. The appeal is still pending.

We expect that our share of these awards, if any, would be credited to our retail customers; however, we are currently unable to predict the outcome of this case.

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	$105.7	$18.8	$0.4
Connecticut Yankee	$137.5	$175.2	$3.5
Yankee Atomic	$90.7	$39.4	$1.4

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 2011 dollars for the period 2012 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 2012 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 2011, 2010 and 2009. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income.

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

Connecticut Yankee: Connecticut Yankee's wholesale rates are currently based on a 2010 FERC-approved filing. Our share of decommissioning and other costs amounted to $0.9 million in 2011 and $0.8 million in 2010 and 2009. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income.

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

Yankee Atomic: Yankee Atomic's wholesale rates are currently based on a 2010 FERC-approved filing. Based on the approved filing, Yankee Atomic agreed to no change in its revenue requirements from the 2006 FERC-approved settlement. The 2006 approved settlement also provides for reconciling and adjusting future charges based on actual decontamination and dismantling expenses and reporting decommissioning trust fund's actual investment earnings. Our share of decommissioning and other costs amounted to $0.4 million in 2011, 2010 and 2009. 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 waste from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel or greater than Class C waste has been collected by the DOE, and each company's spent fuel is stored at its own site. Maine Yankee, Connecticut Yankee and Yankee Atomic collected the funds from us and other wholesale utility customers, under FERC-approved wholesale rates, and our share of these payments was collected from our retail customers.

In 2006, the United States Court of Federal Claims issued judgment in the first phase of 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. This decision was appealed in December 2006, 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 the 1987 annual capacity reports when determining damages.

A final ruling on the remanded case in favor of the three companies was issued on September 7, 2010. Maine Yankee was awarded $81.7 million, Connecticut Yankee was awarded $39.7 million and Yankee Atomic was awarded $21.2 million. The DOE filed an appeal on November 8, 2010 and the three Yankee companies filed cross-appeals on November 19, 2010.

Oral arguments before the United States Court of Appeals for the Federal Circuit were held on November 7, 2011. The court has yet to issue a decision. Interest on the judgments does not start to accrue until the appeals have been decided. Our share of the claimed damages of $3.2 million is based on our ownership percentages described above.

The Court of Federal Claims' original decision established the DOE's responsibility for reimbursing Maine Yankee for its actual costs through 2002 and Connecticut Yankee and Yankee Atomic for their actual costs through 2001. These costs are related to the incremental spent fuel storage, security, construction and other expenses 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, the three companies filed a second round of damage cases against the DOE. On July 1, 2009, Maine Yankee, Connecticut Yankee and Yankee Atomic filed details related to the claimed costs for damages incurred for periods subsequent to the original case discussed above. In this second phase of claims, 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. Our share of the claimed damages in this second round is $6.6 million is based on our ownership percentages described above.

The trial on this second round of claims began October 11, 2011. The DOE has made post-trial filings to keep the record in the cases open while they continue to review documents produced in discovery in an attempt to provide additional trial testimony on selected issues. The three companies have asked for the trial records to be closed in all cases and for a post-trial briefing schedule to be set.

On Thursday March 1, 2012, an order was issued in response to the DOE's motion to compel additional discovery in the Connecticut Yankee and Maine Yankee portions of the case. The Yankee Atomic evidentiary portion has already been closed. This decision closes discovery on Connecticut Yankee, grants potential but limited additional discovery on privileged documents in the Maine Yankee case, and, provides a post-trial briefing schedule that allows the cases to be ready for decision by early May 2012.

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

NOTE 5 - FINANCIAL INSTRUMENTS
The estimated fair value of financial instruments at December 31 follows (dollars in thousands):

	2011		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Power contract derivative assets (includes current portion)	**$4**	**$4**	$28	$28
Power contract derivative liabilities (includes current portion)	**$4,940**	**$4,940**	$0	$0
First mortgage bonds	**$187,500**	**$239,026**	$167,500	$188,467
Industrial/Economic Development bonds	**$40,800**	**$42,691**	$40,800	$40,521
Credit facility borrowings (2010 classified as Notes Payable)	**$12,278**	**$12,278**	$13,695	$13,695

At December 31, 2011, our power-related derivatives consisted of FTRs and forward energy contracts. In 2011, related unrealized losses of $4.9 million were recorded as other deferred charges – regulatory on the Consolidated Balance Sheet and there were no related unrealized gains. In 2010, there were no related unrealized gains or losses. For a discussion of the valuation techniques used for power contract derivatives see Note 6 - Fair Value.

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

The table above does not include cash, special deposits, receivables and payables as the carrying values of those instruments approximate fair value because of their short duration. The carrying values of our variable rate industrial/economic development bonds approximate fair value since the rates are adjusted at least monthly. The carrying value of our credit facility borrowings approximate fair value since the rates can change daily. The fair value of our cash equivalents and restricted cash are included in Note 6 - Fair Value.

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

Our restricted cash is primarily invested with one issuer. However, the issuer is highly rated and the investment is very short-term, maturing in less than 30 days.

Our accounts receivable are not collateralized. As of December 31, 2011, approximately 4.7 percent of total accounts receivable are with wholesale entities engaged in the energy industry. This industry concentration could affect our overall exposure to credit risk, positively or negatively, since customers may be similarly affected by changes in economic, industry or other conditions.

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

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

NOTE 6 - FAIR VALUE

Effective January 1, 2008, we adopted FASB's guidance for fair value measurements. 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. The guidance defines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date."

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

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

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

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

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

Fair Value Hierarchy FASB guidance establishes a fair value hierarchy 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 directly held securities in our non-qualified Millstone Decommissioning Trust Fund.

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

Level 3: Pricing inputs include significant inputs that are generally less observable. Unobservable inputs may be used to measure the asset or liability where observable inputs are not available. We develop these inputs based on the best information available, including our own data. Level 3 instruments include derivatives related to our forward energy purchases and sales, financial transmission rights and a power-related option contract. There were no changes to our Level 3 fair value measurement methodologies during 2011 and 2010.

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, 2011			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities	**$1,621**	**$2,847**		**$4,468**
Marketable debt securities				
Corporate bonds		**356**		**356**
U.S. Government issued debt securities (Agency and Treasury)		**963**		**963**
State and municipal		**88**		**88**
Other		**30**		**30**
Total marketable debt securities		**1,437**		**1,437**
Cash equivalents and other		**45**		**45**
Total investments in securities	**1,621**	**4,329**		**5,950**
Restricted cash - long-term		**2,550**		**2,550**
Cash equivalents	**434**			**434**
Restricted cash		**4,619**		**4,619**
Power-related derivatives - current			**$4**	**4**
Total assets	**$2,055**	**$11,498**	**$4**	**$13,557**
Liabilities:				
Power-related derivatives - current			**$4,940**	**$4,940**
Total liabilities	**$0**	**$0**	**$4,940**	**$4,940**

	Fair Value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities	$1,587	$2,776		$4,363
Marketable debt securities				
Corporate bonds		350		350
U.S. Government issued debt securities (Agency and Treasury)		911		911
State and municipal		38		38
Other		36		36
Total marketable debt securities		1,335		1,335
Cash equivalents and other		44		44
Total investments in securities	1,587	4,155		5,742
Restricted cash - long-term		17,581		17,581
Cash equivalents	1,653			1,653
Restricted cash		5,903		5,903
Power-related derivatives - current			28	28
Total assets	$3,240	$27,639	$28	$30,907

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

We recognize transfers in and out of the fair value hierarchy levels at the end of the reporting period. There were no transfers of equity and debt securities within the fair value hierarchy levels during the period ended December 31, 2011 or December 31, 2010.

Cash Equivalents and Restricted Cash The market approach is used to measure the fair values of money market funds and other short-term investments included in cash equivalents and restricted cash. We have the ability to transact our money market funds at the net asset value price per share and can withdraw those funds without a penalty. We are able to obtain quoted prices for these funds; therefore they are classified as Level 2. We are able to obtain a quoted price for our 90-day commercial paper held in restricted cash; however, the quote was from a less active market. We have concluded that this investment does not qualify for Level 1 and is reflected as Level 2. Cash equivalents are included in cash and cash equivalents on the Consolidated Balance Sheets.

Power-related Derivatives We have historically had three types of derivative assets and liabilities: forward energy contracts, FTRs, and a power-related option contract. At December 31, 2011, our derivatives consisted of forward energy contracts and FTRs. At December 31, 2010, our derivatives consisted of FTRs only. Our primary valuation technique to measure the fair value of these derivative assets and liabilities is the income approach, which involves determining a present value amount based on estimated future cash flows. However, when circumstances warrant, we may also use alternative approaches as described below to calculate the fair value for each type of derivative. Since many of the valuation inputs are not observable in the market, we have classified our derivative assets and liabilities as Level 3.

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

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

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

Level 3 Changes There were no transfers into or out of Level 3 during the periods presented. The following table is a reconciliation of changes in the net fair value of power-related derivatives that are classified as Level 3 in the fair value hierarchy at December 31 (dollars in thousands):

	2011	2010	2009
Balance as of beginning of period	**$28**	$254	$8,820
Gains and losses (realized and unrealized)			
Included in earnings	**(659)**	3,981	23,113
Included in Regulatory and other assets/liabilities	**(4,940)**	(120)	(8,564)
Purchases	**24**	0	0
Net settlements	**611**	(4,087)	(23,115)
Balance at December 31	**($4,936)**	$28	$254

At December 31, 2011 and 2010, there were no realized gains or losses included in earnings attributable to the change in unrealized gains or losses related to derivatives still held at the reporting date. This is due to our regulatory accounting treatment for all power-related derivatives.

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

NOTE 7 - INVESTMENT SECURITIES

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

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

In 2011, we had $0.1 million of realized gains and $0.2 million of realized losses. The realized losses include minimal impairments associated with our equity securities; however, there were no permanent impairments or 'credit losses' associated with our debt securities. There were also no non-credit loss impairments of our debt securities in 2011.

In 2010, we had $0.1 million of realized gains and our realized losses were $0.1 million. The realized losses include $0.1 million of impairments associated with our equity securities; however, there were no permanent impairments or 'credit losses' associated with our debt securities. In addition, there were no non-credit loss impairments to our debt securities in 2010.

The fair values of these investments are summarized below (dollars in thousands):

	As of December 31, 2011			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Marketable equity securities	$3,076	$1,392		$4,468
Marketable debt securities				
Corporate bonds	329	28	($1)	356
U.S. Government issued debt securities (Agency and Treasury)	884	79		963
State and municipal	87	2	(1)	88
Other	29	1		30
Total marketable debt securities	1,329	110	(2)	1,437
Cash equivalents and other	45			45
Total	$4,450	$1,502	($2)	$5,950

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

Information related to the fair value of debt securities at December 31, 2011 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	$66	$268	$318	$785	$1,437

At December 31, 2011, the fair value of debt securities in an unrealized loss position was $0.1 million. At December 31, 2010, the fair value of debt securities in an unrealized loss position was $0.2 million.

NOTE 8 – RESTRICTED CASH

The amount of restricted cash related to unreimbursed VEDA bond financing proceeds was $6.1 million at December 31, 2011 and $23.5 million at December 31, 2010.

At December 31, 2011, we had invested in a restricted cash account related to. The investments consist primarily of commercial paper.

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

As of December 31, 2011, we recorded $3.5 million of the restricted cash as a current asset on the Consolidated Balance Sheet representing expenses paid that are expected to be reimbursed at the next requisition date. To date we have received reimbursements of $24 million. We expect to receive reimbursements of the remaining proceeds held in trust during 2012.

In September 2011, we received $1.1 million from Omya for the repayment obligation for the five-year rate phase-in plan of the former Vermont Marble customers, as specified in the acquisition agreement between CV and Omya. As of December 31, 2011, the $1.1 million was included in the current portion of restricted cash.

NOTE 9 - RETAIL RATES AND REGULATORY ACCOUNTING

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

Alternative Regulation: On September 30, 2008, the PSB issued an order approving our alternative regulation plan. The plan became effective on November 1, 2008. It was scheduled to expire on December 31, 2011. The plan allows for quarterly PCAM adjustments to reflect changes in power supply and transmission-by-others costs and annual base rate adjustments to reflect changes in operating costs; and an annual ESAM adjustment to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity is adjusted annually to reflect one-half of the change in the average yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The ESAM provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to customers in a future period. If the actual return on equity of our regulated business falls between 75 and 125 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and customers. Any earnings shortfall in excess of 125 basis points below the allowed return on equity is fully recovered from customers. As such, the minimum return for our regulated business is 100 basis points below the allowed return. These adjustments are made at the end of each fiscal year.

The ESAM also provides for an exogenous effects provision. Under this provision, we are allowed to defer the unexpected impact if in excess of $0.6 million, of changes in GAAP, tax laws, FERC or ISO-NE rules and major unplanned operation, maintenance costs, such as those due to major storms and other factors including loss of load not due to variations in heating and cooling temperatures. In 2011, we deferred $7.5 million of costs related to Tropical Storm Irene and legislative and tax law changes. We plan to file with the PSB by May 1, 2012, for recovery of these costs commencing on July 1, 2012 as provided by our alternative regulation plan.

By order dated March 3, 2011, the PSB approved amendments to the alternative regulation plan that: 1) extend its duration until December 31, 2013; 2) alter the methodology for implementing the non-power cost cap contained in the plan; 3) reset our allowed ROE to 9.45 percent; and 4) remove provisions no longer applicable to the provision of our services.

Using the methodology specified in our alternative regulation plan, we estimated our 2011 return on equity from the regulated portion of our business to be approximately 9.09 percent. We are required to file this calculation with the PSB by May 1, 2012. No ESAM adjustment was required since this return was within 75 basis points of our 2011 allowed return on equity of 9.45 percent.

The PCAM adjustment for the fourth quarter of 2011 was an over-collection of $0.3 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending June 30, 2012. We filed a PCAM report with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

The PCAM adjustment for the third quarter of 2011 was an under-collection of $0.3 million and was recorded as a current asset. This under-collection will be collected from customers over the three months ending March 31, 2012. We filed a PCAM report with the PSB identifying this under-collection. The DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing.

The PCAM adjustment for the first quarter of 2011 was an over-collection of $1 million and for the second quarter of 2011 was an over-collection of $0.8 million. These amounts were recorded as current liabilities and were returned to customers over the three months ending September 30, 2011 for first quarter and ending December 31, 2011 for the second quarter.

On November 1, 2011, we submitted a base rate filing for the rate year commencing January 1, 2012, as required by our alternative regulation plan. The filing proposes an increase in base rates of $15.8 million or a 4.78 percent increase in retail rates, reflecting an allowed ROE of 9.17 percent. 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, less a productivity adjustment that varies based upon the results of a comparison of certain cost metrics of the company with those of a benchmark group of U.S. electric utilities. For the 2012 rate year, the productivity adjustment was 0.95 percent. The non-power costs associated with the implementation of our Asset Management Plan and our CVPS SmartPower® project are excluded from the non-power cost cap. Our 2012 forecasted non-power costs did not exceed the non-power cost cap. On December 28, 2011, we received approval from the PSB and the 4.78 rate increase went into effect January 1, 2012.

CVPS SmartPower® On October 27, 2009, the DOE announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation.

On April 15, 2010, we signed an agreement with the DOE for our portion of the Smart Grid stimulus grant and project and the agreement became effective April 19, 2010. The agreement includes provisions for funding and other requirements. We are allowed to receive reimbursement of 50 percent of our total eligible project costs incurred since August 6, 2009, up to $31 million. From the inception of the project through December 31, 2011, we have incurred $13.8 million of costs, of which $7.7 million were operating expenses and $6.1 million were capital expenditures. In 2011, we have incurred $9.2 million of costs, of which $5.3 million were operating expenses and $3.9 million were capital expenditures.

We have submitted requests for reimbursement of $6.2 million and have received $5 million to date, of which $3.3 million was received in 2011.

On July 19, 2011, we entered into a contract for the communications infrastructure in support of our advanced metering project. The overall contract is approximately $6.2 million for which we are jointly and severally liable with another party. Our share of the contract cost is approximately $3.9 million. The contract calls for a $1.9 million initial payment with remaining payments for certain milestones to be made over a two-year period. In August 2011, we made the initial payment of $1.9 million and received 50 percent reimbursement from the DOE.

Pending Merger with Gaz Métro Also, see Note 1 - Business Organization, Pending Merger with Gaz Métro, Regulatory approvals.

Regulatory Accounting Under the 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 $11.5 million of regulatory assets (total regulatory assets of $49 million less pension and postretirement medical costs of $37.5 million), $13.8 million of other deferred charges - regulatory and $4.1 million of other deferred credits - regulatory. This would result in a total charge to operations of $21.2 million on a pre-tax basis as of December 31, 2011. We would be required to record pre-tax pension and postretirement costs of $37.3 million to Accumulated Other Comprehensive Loss and $0.2 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, 2011	December 31, 2010
Regulatory Assets - Long-term Portion:		
Pension and postretirement medical costs	**$37,300**	$27,959
Nuclear plant dismantling costs	**3,827**	5,383
Income taxes	**4,722**	4,480
Asset retirement obligations (a) (d)	**426**	487
Other (b) (d)	**106**	243
Total Regulatory Assets -Long-term Portion	**46,381**	38,552
Regulatory Assets - Current Portion:		
Pension and postretirement medical costs (c) (d)	**235**	0
Nuclear refueling outage costs - Millstone Unit #3 (c) (d)	**805**	486
Nuclear plant dismantling costs (c) (d)	**1,433**	1,438
Asset retirement obligations and other (c) (d)	**132**	0
Total Regulatory Assets - Current Portion	**2,605**	1,924
Total Regulatory Assets	**$48,986**	$40,476

Other Deferred Charges - Regulatory - Long-term Portion:		
ESAM deferred costs (b) (d)	**$3,759**	$2,079
Environmental (d)	**108**	0
FERC relicensing	**609**	0
Other (d)	**147**	181
Total Other Deferred Charges - Regulatory - Long-term Portion	**4,623**	2,260
Other Deferred Charges - Regulatory - Current Portion:		
Unrealized loss on power-related derivatives (c)	**4,940**	0
ESAM deferred costs (c) (d)	**3,759**	2,078
Other (c) (d)	**503**	0
Total Other Deferred Charges - Regulatory - Current Portion	**9,202**	2,078
Total Other Deferred Charges - Regulatory	**$13,825**	$4,338
Other Deferred Credits - Regulatory - Long-term Portion:		
Asset retirement obligation - Millstone Unit #3	**$3,060**	$3,009
CVPS SmartPower® grant reimbursements	**0**	222
Other (c) (d)	**21**	655
Total Other Deferred Credits - Regulatory - Long-term Portion:	**3,081**	3,886
Other Deferred Credits - Regulatory - Current Portion:		
CVPS SmartPower® grant reimbursements (c) (d)	**222**	958
Other (c) (d)	**825**	150
Total Other Deferred Credits - Regulatory - Current Portion	**1,047**	1,108
Total Other Deferred Credits - Regulatory	**$4,128**	$4,994

(a) Remaining recovery period is 14 years
(b) Remaining recovery period is two years
(c) Remaining recovery period is one year
(d) Currently earning a return

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. Other deferred charges – regulatory are supported by PSB-approved accounting orders or approved cost recovery methodologies, allowing cost deferral until recovery in a future rate proceeding. Most items listed in other deferred credits - regulatory are being amortized for periods ranging from two to three years. Pursuant to PSB-approved rate orders, when a regulatory asset or liability is fully amortized, the corresponding rate revenue shall be booked as a reverse amortization in an opposing regulatory liability or asset account.

Regulatory assets for pension and postretirement medical costs are discussed in Note 12 - Pension and Postretirement Medical Benefits. Regulatory assets for nuclear plant dismantling costs are related to our equity interests in Maine Yankee, Connecticut Yankee and Yankee Atomic which are described in Note 4 - Investments in Affiliates. Power-related derivatives are discussed in more detail in Note 6 - Fair Value.

NOTE 10 - SHARE-BASED COMPENSATION

We have awarded share-based compensation to key employees and non-employee directors under several stock compensation plans. Awards under these plans have been comprised of stock options, common stock and performance shares. The last stock option awards were made in 2005 and we do not anticipate making additional awards. At December 31, 2011 these plans included:

Plan	Shares Authorized	Stock Options Outstanding	Shares Available for Future Grant
1997 Stock Option Plan - Key Employees	350,000	33,948	0
2000 Stock Option Plan - Key Employees	350,000	96,880	0
Omnibus Stock Plan (a)	450,000	99,592	80,374
Total	1,150,000	230,420	80,374

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

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

Total share-based compensation expense recognized in the Statement of Income was $0.9 million in 2011, 2010 and 2009. The total income tax benefit recognized in the Statement of Income for share-based compensation was $0.4 million in 2011, $0.3 million in 2010 and $0.4 million in 2009. No compensation costs were capitalized. Cash received from exercise of stock options was $0.9 million in 2011, $0.6 million in 2010 and $0.4 million in 2009. The tax benefit realized for the tax deductions from option exercises and performance shares issued was $0.4 million in 2011, $0.2 million in 2010 and $0.3 million in 2009. These amounts are included in other paid in capital on the balance sheet.

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

Stock Options All outstanding stock options were granted at the fair market value of the common shares on the date of grant, and vested immediately. The maximum term of options is five years for non-employee directors and 10 years for key employees. Stock option activity during 2011 follows:

	Shares	Weighted Average Exercise Price
Options outstanding and exercisable at January 1	284,997	$19.13
Exercised	50,677	$17.75
Granted	0	
Forfeited	0	
Expired	3,900	
Options outstanding and exercisable at December 31	230,420	$19.49

The total intrinsic value of stock options exercised during the last three years was $0.6 million in 2011, $0.4 million in 2010 and $0.3 million in 2009. The aggregate intrinsic value of options outstanding and exercisable as of December 31, 2011 was $3.6 million. The weighted-average remaining contractual life for options outstanding and exercisable as of December 31, 2011 was 2 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 2011 follows:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	0	
Granted	13,537	$25.66
Vested	(3,928)	$27.98
Deferred	(4,910)	$27.98
Forfeited	0	
Nonvested at December 31	4,699	$21.28

Common stock is granted as part of the Board of Directors' annual retainer. These shares vest immediately, however, individual directors can elect to defer receipt of their retainer under the terms of the Deferred Compensation Plan for Directors and Officers. Compensation expense was $0.3 million in 2011 and $0.2 million in both 2010 and 2009. Unearned compensation expense at December 31, 2011 was $0.1 million.

The weighted-average grant-date fair value per share granted was $25.66 in 2011, $21.17 in 2010, $18.04 in 2009. The fair value of shares vested totaled approximately $0.1 million in 2011, 2010 and 2009.

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

The fair value of performance shares for operational measures was estimated based on the market value of the shares on the grant date and the expected outcome of each measure. The grant-date fair value of performance shares with operational measures granted in 2011 was $22.01 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 2011 was $22.21 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.

	2011	2010	2009
Volatility	39.00%	42.00%	42.30%
Risk-free rate of return	0.98%	1.53%	1.09%
Dividend yield	4.50%	4.75%	4.07%
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 2011 follows:

	Shares	Weighted Average Grant-Date Fair Value
Outstanding at January 1	63,400	$19.87
Contingently granted for the 2011 - 2013 performance cycle	31,700	$22.11
Vested for the 2009 - 2011 performance cycle	(35,044)	$19.41
Forfeited	(18,056)	$21.10
Outstanding at December 31	42,000	$21.13

Compensation expense for performance share plans amounted to $0.6 million in both 2011 and 2010 and $0.7 million in 2009. Unrecognized compensation expense for outstanding performance shares based on anticipated performance levels as of December 31, 2011 is approximately $0.3 million and is expected to be recognized over 1.5 years.

In the first quarter of 2011, a total of 12,138 common shares were issued for the 2008-2010 performance cycle, of which the participants withheld receipt of 3,438 shares to satisfy withholding tax obligations. Executive officers can elect to defer the receipt of performance shares. In the first quarter of 2011 a total of 2,713 common shares were deferred. The fair value of shares vested at December 31, 2010 was $0.3 million based on the goals that were achieved for the 2008 - 2010 performance cycle.

In the second quarter of 2011, the Board of Directors approved the issuance of 17,083 shares to an officer who retired effective May 31, 2011. There were 9,477 shares issued for the 2009-2011 performance cycle, 6,004 shares issued for the 2010-2012 performance cycle and 1,602 shares issued for the 2011-2013 performance cycle. The retiring officer elected to withhold receipt of 5,670 shares to satisfy withholding tax obligations. The fair value of shares vested at May 31, 2011 was $0.6 million based on a pro-rata number of shares at target performance for all three open performance cycles.

In December 2011, the fair value of performance shares that were earned or vested, including dividend equivalents, based on goals that were achieved for the 2009 - 2011 performance cycle was $0.9 million. The Board of Directors approved the early issuance of the 2009-2011 performance shares on December 16, 2011. In the fourth quarter of 2011, a total of 26,353 common shares were issued for the 2009 - 2011 performance cycle, of which the participants withheld receipt of 5,153 shares to satisfy withholding tax obligations. Executive officers can elect to defer the receipt of performance shares. In the fourth quarter of 2011 a total of 10,831 common shares were deferred.

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

NOTE 11 - COMMON STOCK

On November 6, 2009, we filed a Registration Statement with SEC on Form S-3, requesting the ability to offer, from time to time and in one or more offerings, up to $55 million of our common stock. On December 4, 2009, the SEC declared the Registration Statement to be effective. On January 15, 2010, we filed a Prospectus Supplement with the SEC, noting that we entered into an equity distribution agreement that allowed us to issue up to $45 million of shares under an "at-the-market" program.

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

NOTE 12 - TREASURY STOCK

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

NOTE 13 - PREFERRED AND PREFERENCE STOCK NOT SUBJECT TO MANDATORY REDEMPTION
Preferred and preference stock not subject to mandatory redemption at December 31 follows (dollars in thousands):

	2011	2010
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, 2011, a total of 80,538 shares were outstanding, none of which are subject to mandatory redemption and are listed in the table above. None of the outstanding Preferred Stock, $100 Par Value, is convertible into shares of any other class or series of our capital stock or any other security.

There are 1,000,000 shares authorized of Preferred Stock, $25 Par Value, and 1,000,000 shares authorized of Preference Stock, $1 Par Value. None of the shares are subject to mandatory redemption. There were none outstanding, issued or redeemed in 2011, 2010, or 2009.

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, 2011, premiums payable on each series of non-redeemable preferred stock if such an event were to occur are as follows:

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

NOTE 14 - LONG-TERM DEBT AND NOTES PAYABLE

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

	December 31, 2011	December 31, 2010
First Mortgage Bonds		
5.00%, Series SS, due 2011	**$0**	$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
5.89%, Series WW, due 2041	**40,000**	0
Industrial/Economic Development Bonds		
Vermont Industrial Development Authority Bonds ("VIDA")		
Variable, due 2013 (0.15% at December 31, 2011 and 0.35% at December 31, 2010)	**5,800**	5,800
Connecticut Development Authority Bonds ("CDA")		
Variable, due 2015 (0.20 % at December 31, 2011 and 0.35% at December 31, 2010)	**5,000**	5,000
Vermont Economic Development Authority Bond ("VEDA") 5.00%, due 2020	**30,000**	30,000
Credit Facility		
$40 million unsecured revolving credit facility		
(1.5375% at December 31, 2011 and 0.95% at December 31, 2010)	**12,278**	13,695
Total long-term debt and notes payable	**240,578**	221,995
Less current amount of long-term debt, due within one year	**0**	(20,000)
Less credit facility, due within one year	**0**	(13,695)
Total long-term debt, less current portion	**$240,578**	$188,300

First Mortgage Bonds: Substantially all of our utility property and plant is subject to liens under our First Mortgage Bond indenture. There are no interim sinking fund payments due prior to maturity on any series of first mortgage bonds and all interest rates are fixed. The First Mortgage Bonds are callable at our option at any time upon payment of a make-whole premium, calculated as the excess of the present value of the remaining scheduled payments to bondholders, discounted at a rate that is 0.5 percent higher than the comparable U.S. Treasury Bond yield, over the early redemption amount.

On June 15, 2011, we issued $40 million of First Mortgage 5.89 percent Bonds, Series WW and $20 million of this amount was used to redeem the Series SS Bonds. The Series WW bonds were issued to one purchaser, in a private placement transaction, under a shelf facility that was put in place on February 4, 2011. The Series WW bond issuance was planned when we entered into a commitment with the purchaser on July 15, 2010 to issue $40 million of first mortgage bonds at 5.89 percent on June 15, 2011 in a private placement transaction. The remaining proceeds are being used for our capital expenditures and for other corporate purposes. The shelf facility allows us to issue up to an additional $60 million of first mortgage bonds directly to the purchaser through December 31, 2012. Neither party has any obligation to issue or purchase the additional $60 million first mortgage bonds available under the shelf facility.

Industrial/economic development bonds: The CDA and VIDA bonds are tax-exempt, floating rate, monthly demand revenue bonds. There are no interim sinking fund payments due prior to their maturity. The interest rates reset monthly. Both series are callable at par as follows: 1) at our option or the bondholders' option on each monthly interest payment date; or 2) at the option of the bondholders on any business day. There is a remarketing feature if the bonds are put for redemption. Historically, these bonds have been remarketed in the secondary bond market. These two series of bonds are both supported by letters of credit, discussed below.

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

Our first mortgage bond and industrial/economic development bond financing documents do not contain cross-default provisions to affiliates outside of the consolidated entity. Certain of our debt financing documents contain cross-default provisions to our wholly owned subsidiaries, East Barnet and C.V. Realty, Inc. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions, a breach of warranty or performance of an obligation, or the levy of significant judgments, attachments against our property or insolvency. Currently, we are not in default under any of our debt financing documents. Scheduled maturities for the next five years are $0 in 2012, $5.8 million in 2013, $0 in 2014, $5 million in 2015 and $0 in 2016.

Letters of credit: We have two outstanding unsecured letters of credit, issued by one bank, that support the CDA and VIDA revenue bonds. These letters of credit total $11.1 million in support of the two revenue bond issues totaling $10.8 million, discussed above. We pay an annual fee of 2.4 percent on the letters of credit. These letters of credit expire on November 30, 2012. The letters of credit contain cross-default provisions to our wholly owned subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or insolvency. At December 31, 2011, there were no amounts drawn under these letters of credit.

Credit Facility: We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated October 25, 2011 that expires on October 24, 2014. This facility replaced a three-year, $40 million unsecured revolving credit facility that matured on November 2, 2011. The Credit Agreement contains financial and non-financial covenants. 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 1.35 percent on the average daily amount of letters of credit outstanding. The facility does not contain a Material Adverse Effect clause. 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, 2011, there were $12.3 million in loans and $3.5 million in letters of credit outstanding under this credit facility. At December 31, 2010, there were $13.7 million in loans and $5.5 million in letters of credit outstanding under the previous credit facility.

We also have a three-year, $15 million unsecured revolving credit facility with a different lending institution pursuant to a Credit Agreement dated December 22, 2010 that expires in December 2013. This facility replaced a 364-day $15 million unsecured revolving credit facility that matured on December 29, 2010. The purpose of and our obligation under this credit agreement is the same as described above. Financing terms and costs include an annual commitment fee of 0.5 percent on the unused balance and a fee of 2.0 percent on the average daily amount of letters of credit outstanding. Various interest rate options exist for amounts borrowed under this facility. This facility also does not contain a Material Adverse Effect clause. This facility was not used in 2011 or 2010 for borrowings or letters of credit.

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

Dividend and Optional Stock Redemption Restrictions: Our revolving credit facilities described above restricts optional redemptions of capital stock and other restricted payments as defined. The First Mortgage Bond indenture and our Articles of Association also contain certain restrictions on the payment of cash dividends on and optional redemptions of all capital stock. Under the most restrictive of these provisions, $79.9 million of retained earnings was not subject to such restriction at December 31, 2011. 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 15 - 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 early 2012. Because of this projected power surplus, we entered into one forward power sale contract for 2011. The 2011 forward sale was initially structured as a physical sale of excess power. In January 2011 the sale contract was renegotiated as a rate swap that settles financially. We recently entered into a similar rate swap for the sale of excess power in January and February 2012. We have concluded that neither the 2011 or 2012 rate swaps are derivatives, since a notional amount does not exist under the terms of either contract.

On occasion, we will forecast a temporary power supply shortage such as when Vermont Yankee becomes unavailable. We typically enter into short-term forward power purchase contracts to cover a portion of these expected power supply shortages, which helps to reduce price volatility in our net power costs. In 2011, we entered into a 26-day purchase contract to cover the expected power supply shortage during the 2011 Vermont Yankee refueling outage, which ended November 3, 2011.

Our power supply forecast shows that in early 2012, when our long-term contract with Vermont Yankee expires, our load requirements will begin to exceed the level of energy we currently purchase and produce. In July 2011, we entered into two contracts to fill what would have been power supply shortages expected between April and December 2012.

In September 2011, in connection with the Vermont Marble acquisition, we assumed two forward purchase contracts. The Vermont Marble contracts provide for nominal deliveries of physical power between September 2011 and December 2012, and we determined that these purchase contracts are derivatives.

We have determined that the power purchase contracts we entered into for 2011 and 2012 are derivatives. We did not elect the "normal purchase, normal sale" exception for any of these short-term power purchase contracts.

On August 12, 2010, we executed a significant long-term power purchase contract with HQUS and we have concluded that this contract meets the "normal purchase, normal sale" exception to derivatives accounting; therefore, we are not required to calculate the fair value of this contract. For additional information on this contract, see Note 18 - Commitments and Contingencies.

We are able to economically hedge our exposure to congestion charges that result from constraints on the transmission system with FTRs. FTRs are awarded to the successful bidders in periodic auctions administered by ISO-NE.

We do not use derivative financial instruments for trading or other purposes. Accounting for power-related derivatives is discussed in Note 2- Summary of Significant Accounting Policies.

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

	MWh (000s)	
	2011	**2010**
Commodity		
Forward Energy Purchase Contracts	535.3	0
Financial Transmission Rights	326.9	1,958.3

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

	2011	2010	2009
Net realized gains (losses) reported in operating revenues	**$0**	$4,581	$23,226
Net realized gains (losses) reported in purchased power	**(659)**	(600)	(113)
Net realized gains (losses) reported in earnings	**($659)**	$3,981	$23,113

Realized gains and losses on derivative instruments are conveyed to or recovered from customers through the PCAM and have no net impact on results of operations. Derivative transactions and related collateral requirements are included in net cash flows from operating activities in the Consolidated Statements of Cash Flows. For information on the location and amounts of derivative fair values on the Consolidated Balance Sheets see Note 6 - Fair Value.

Certain of our power-related derivative instruments contain provisions for performance assurance that may include the posting of collateral in the form of cash or letters of credit, or other credit enhancements. Our counterparties will typically establish collateral thresholds that represent credit limits, and these credit limits vary depending on our credit rating. If our current credit rating were to decline, certain counterparties could request immediate payment and full, overnight ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk related contingent features that were in a liability position at December 31, 2011 was $3.8 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 issuer credit rating to Ba1, we would be required to post $3.3 million of collateral with our counterparties, upon their request. If our Moody's credit rating were further lowered to Ba2, our counterparties could request an additional $0.5 million of collateral. For information concerning performance assurance, see Note 18 - Commitments and Contingencies.

NOTE 16 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

We have a qualified, non-contributory, defined-benefit pension plan covering unionized and non-unionized employees hired prior to April 1, 2010, subject to certain eligibility criteria. Under the terms of the Pension Plan, employees are vested after completing five years of service, and can receive a pension benefit when they are at least age 55 with a minimum of 10 years of service. They are eligible to choose between various payment options such as a monthly benefit or a one-time lump-sum amount depending on factors such as years of service earned at the date of retirement. Our funding policy is to contribute to the pension trust fund the greater of the IRS deductible annual actuarial cost or the statutory minimum.

On November 9, 2009, our board of directors voted to approve changes to the pension plan and 401(k) plan with a conversion date of April 1, 2010. The pension plan described above was closed to employees hired after the conversion date. All employees hired after the conversion date are now given, in addition to the existing match on 401(k) contributions up to 4.25 percent, a core 401(k) contribution of 3 percent of base pay, or a total of up to 7.25 percent. The core contribution will be subject to a three-year cliff vesting schedule. For employees hired before the conversion date, the pension benefits described above will remain in effect. In addition, employees hired before the conversion date receive a core 401(k) contribution of .50 percent of eligible base pay into the 401(k) plan in addition to the current 401(k) company match of up to 4.25 percent, or a total of up to 4.75 percent. The pension plan was also enhanced on the conversion date by offering the so-called "Rule of 85." Under the Rule of 85, if an employee is at least 55 years old with 10 years of service and their combined service and age totals at least 85, they will be eligible for an unreduced pension benefit.

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

Beginning in 2009, the postretirement benefit was enhanced with sharing of one-half of the Medicare Part D subsidy that we received. Under this enhancement, we split the shared subsidy portion evenly between the pre-age 65 and post-age 65 retiree plans. Medicare Part D reduced our postretirement medical benefit costs by less than $0.1 million in 2011, $0.8 million in 2010 and $1.7 million in 2009.

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

Benefit Obligation The changes in benefit obligation for pension and postretirement medical benefits at the December 31, 2011 and 2010 measurement dates follow (dollars in thousands):

	Pension Benefits		Postretirement Medical Benefits	
	2011	2010	**2011**	2010
Benefit obligation at beginning of fiscal year	**$128,502**	$116,958	**$25,241**	$28,861
Service cost	**4,566**	4,103	**793**	912
Interest cost	**7,403**	7,016	**1,318**	1,580
Plan participants' contributions	**0**	0	**700**	606
Actuarial loss (gain)	**9,431**	7,223	**(757)**	(4,706)
ERRP proceeds	**0**	0	**13**	0
Gross benefits paid	**(10,877)**	(6,798)	**(2,141)**	(2,242)
less: federal subsidy on benefits paid	**0**	0	**234**	230
Plan amendments	**0**	0	**0**	0
Benefit obligation at fiscal year end	**$139,025**	$128,502	**$25,401**	$25,241
Accumulated obligation as of measurement date (December 31)	**$113,769**	$105,930	n/a	n/a

The reduction in our accumulated postretirement benefit obligation due to the impact of the Medicare Part D subsidy was $0.2 million for 2011 and $0.5 million for 2010.

The present value of future contributions from Postretirement Plan participants was $37 million for 2011 and $31.7 million for 2010.

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at the December 31 measurement date for 2011 and 2010 are shown in the table that follows. The selection methodology used in determining discount rates includes portfolios of "Aa"-rated bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million in par value. The following weighted-average assumptions for pension and postretirement medical benefits were used in determining our related liabilities at December 31:

	Pension Benefits		Postretirement Medical Benefits	
	2011	2010	**2011**	2010
Discount rates	**5.20%**	5.75%	**4.85%**	5.25%
Rate of increase in future compensation levels	**4.25%**	4.25%	**4.25%**	4.25%

For measurement purposes, an 8.0 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2011, for pre-age 65 and post-age 65 participant claims costs. The rate is assumed to remain at 8.0 percent through 2013, and then the rate is assumed to decrease 0.5 percent each year until 2019 when an estimated ultimate trend rate of 5.0 percent is reached.

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

	Increase	Decrease
Effect on postretirement medical benefit obligation as of December 31, 2011	$2,187	($1,809)
Effect on aggregate service and interest costs	*$205*	*($168)*

Asset Allocation The asset allocations at the measurement date for 2011 and 2010, and the target allocation for 2012, by asset category, are as follows:

	Pension Plan			Postretirement Medical Plan		
	2012 Target	**2011**	2010	**2012 Target**	**2011**	2010
Equity securities	**37%**	39%	58%	**60%**	59%	62%
Debt securities	**53%**	51%	42%	**40%**	41%	38%
Other	**10%**	10%	0%	**0%**	0%	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, maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that approximately 38 percent of plan assets be invested in equity securities, 52 percent of plan assets be invested in debt securities and 10 percent of assets be invested in alternative investments. The asset allocation guidelines will automatically adjust to predetermined levels as the plan's funded status improves. This approach is expected to reduce the risk of loss in the overall pension portfolio. The debt securities are primarily comprised of long-duration bonds to match changes in plan liabilities.

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

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

To mitigate concentrations of risk arising from our benefit plan investments in securities, we pursue a range of investment strategies using a well-diversified array of equity, fixed income and alternative 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 funded status. Approximately 30 percent of our liabilities are duration-matched with plan assets.

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

	Pension Plan		Postretirement Medical Plan	
	2011	2010	**2011**	2010
Fair value of plan assets at beginning of fiscal year	**$107,434**	$97,205	**$18,407**	$15,027
Actual return on plan assets	**7,030**	13,731	**55**	2,239
Employer contributions	**4,143**	3,296	**1,602**	2,777
Plan participants' contributions	**0**	0	**700**	606
Gross benefits paid	**(10,877)**	(6,798)	**(2,141)**	(2,242)
Fair value of assets at fiscal year end	**$107,730**	$107,434	**$18,623**	$18,407

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

	Pension Plan		Postretirement Medical Plan	
	2011	2010	**2011**	2010
Fair value of assets	**$107,730**	$107,434	**$18,623**	$18,407
Benefit obligation	**(139,025)**	(128,502)	**(25,401)**	(25,241)
Funded Status	**($31,295)**	($21,068)	**($6,778)**	($6,834)

The decrease in the Pension Plan funded status of $10.2 million for 2011 versus 2010 resulted from a increase of $0.3 million in the fair value of assets as shown in the table above, and an increase of $10.5 million in the benefit obligation, primarily due to actual gains on plan assets as shown in the tables above and changes in actuarial assumptions including the discount rate.

The increase in the Postretirement Medical Plan funded status of $0.1 million for 2011 versus 2010 resulted from an increase of $0.2 million in the fair value of assets as shown in the table above, offset by an increase of $0.1 million in the benefit obligation, primarily due to the reasons described above and employer contributions.

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

Valuation Techniques: Fair value guidance emphasizes that market-based measurement should be based on assumptions that market participants would use to price the benefit plan assets. The fair value guidance includes three valuation techniques to be used at the initial recognition and subsequent measurement of benefit plan assets: 1) Market Approach; 2) Income Approach; and 3) Cost Approach. Also see Note 6 - Fair Value for additional information about these valuation techniques.

The valuation technique used to determine the fair value of the debt and equity securities included in our pension and postretirement medical trust funds is the market approach. The securities are considered to be Level 1 in the fair value hierarchy since quoted prices are available in active markets for these assets. The fair value of the alternative investments is estimated using significant unobservable inputs. Because of this and because we are not assured of the ability to redeem these investments at net asset value as of the measurements date or within the near term, alternative investments are classified as Level 3.

Our alternative investments consist of two multi strategy hedge fund of funds and a diversified strategy of real estate property funds. The hedge funds carry one and two year lock-up provisions. All funds can be redeemed either quarterly or semi-annually with a 65-day or 95-day pre-notification, though redemptions of the real estate fund may be subject to queue. All funds carry a ten percent holdback on final payment, held in escrow until completion of the funds' audits.

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 2012	Pension Plan Fair Value as of December 31, 2011			
		Level 1	Level 2	Level 3	Total
Marketable equity securities					
U.S. Large cap	18%	21,583			$21,583
U.S. Small and mid cap	5%	5,732			$5,732
International	12%	11,647			$11,647
Other	2%	2,723			$2,723
Total marketable equity securities	37%	41,685	0	0	$41,685
Marketable debt securities					
Corporate bonds	44%	28,533			$28,533
U.S. Government issued debt securities		12,029			$12,029
U.S. Agency debt		1,212			$1,212
Non-corporate		2,857			$2,857
High yield debt	4%	5,602			$5,602
Emerging markets debt	3%	2,772			$2,772
Other	2%	2,242			$2,242
Total marketable debt securities	53%	55,247	0	0	$55,247
Hedge funds	5%			5,303	$5,303
Real estate fund	5%			5,285	$5,285
Cash and cash equivalents					$0
Other		210			$210
Total	100%	$97,142	$0	$10,588	$107,730

	Target Allocation 2011	Pension Plan Fair Value as of December 31, 2010			
		Level 1	Level 2	Level 3	Total
Marketable equity securities					
U.S. Large cap	31%	$34,893			$34,893
U.S. Small and mid cap	5%	5,645			5,645
International	18%	21,209			21,209
Other					0
Total marketable equity securities	54%	$61,747	0	0	$61,747
Marketable debt securities					
Corporate bonds	33%	$20,958			$20,958
U.S. Government issued debt securities		8,058			8,058
U.S. Agency debt		666			666
Non-corporate		1,774			1,774
High yield debt	10%	10,640			10,640
Emerging markets debt	3%	3,100			3,100
Other		282			282
Total marketable debt securities	46%	$45,478	0	0	$45,478
Cash and cash equivalents		0			0
Other		209			209
Total	100%	$107,434	$0	$0	$107,434

	Target Allocation 2012	Postretirement Medical Plan Fair Value as of December 31, 2011			
		Level 1	Level 2	Level 3	Total
Marketable equity securities					
U. S. Large cap	35%	6,778			$6,778
U. S. Small and mid cap	9%	1,656			$1,656
International	16%	2,787			$2,787
Other					$0
Total marketable equity securities	60%	11,221	0	0	$11,221
Marketable debt securities					
Corporate bonds	35%	1,553			$1,553
U.S. Government issued debt securities		1,044			$1,044
U.S. Agency debt		2,159			$2,159
State and municipal		138			$138
High yield debt	5%	1,021			$1,021
Other		1,783			$1,783
Total marketable debt securities	40%	7,698	0	0	$7,698
Cash and cash equivalents					$0
Other		28			$28
Total Fair Value	100%	18,947	0	0	$18,947
Less amounts due from Trust to CVPS at December 31, 2011					$324
Net Plan Assets					$18,623

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

Level 3 Changes There were no transfers into or out of Level 3 during the periods presented. The following table is a reconciliation of changes in the net fair value of pension assets that are classified as Level 3 in the fair value hierarchy at December 31 (dollars in thousands):

	Hedge Funds	Real Estate	2011 Total
Balance Beginning of Period	$0	$0	$0
Gains and losses (realized and unrealized)			
Included in earnings	0	0	0
Included in regulatory and other assets/liability	(78)	0	(78)
Purchases	5,381	5,285	10,666
Balance at December 31	**$5,303**	**$5,285**	**$10,588**

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

	Pension Benefits		Postretirement Medical Benefits	
	2011	2010	**2011**	2010
Current liability	**$0**	$0	**($89)**	($179)
Non-current liability	**(31,295)**	(21,068)	**(6,689)**	(6,655)
Total	**($31,295)**	($21,068)	**($6,778)**	($6,834)

At December 31, 2011, 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 2012.

Amounts recognized in Regulatory Assets and Accumulated Other Comprehensive Loss The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2011 consisted of (dollars in thousands):

	Regulatory Asset	AOCL	Total	Regulatory Asset	AOCL	Total
Net actuarial loss	$29,032	$97	$29,129	$4,335	$15	$4,350
Prior service cost	2,159	$7	2,166	1,513	5	1,518
Transition obligation	0	0	0	191	1	192
Net amount recognized	$31,191	$104	$31,295	$6,039	$21	$6,060

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

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

Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets and Other Comprehensive Income Components of pre-tax changes from 2010 to 2011 were as follows (dollars in thousands):

	Pension Benefits			*Postretirement Medical Benefits*		
	Regulatory Asset	**AOCL**	**Total**	**Regulatory Asset**	**AOCL**	**Total**
Amounts amortized during the year						
Net transition (obligation)/asset	$0	$0	$0	($256)	$0	($256)
Net prior service (cost)/credit	(413)	(1)	(414)	(278)	(1)	(279)
Net (loss)/gain	(239)	(1)	(240)	(201)	(1)	(202)
Amounts arising during the year						
*Net loss/(gain)	10,842	39	10,881	346	3	349
Net amount recognized	$10,190	$37	$10,227	($389)	$1	($388)

*includes loss/gain of $46,840 related to Medicare Part D subsidy receipts in 2011, lower/(higher) than expected, and ERRP proceeds of $312,015 to reduce the company's cost of providing retiree drug benefits.

Components of pre-tax changes from 2009 to 2010 were as follows (dollars in thousands):

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

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

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

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

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

	Pension Benefits			Postretirement Benefits		
	2011	2010	2009	**2011**	2010	2009
Service cost	**$4,566**	$4,103	$3,783	**$793**	$912	$710
Interest cost	**7,403**	7,016	6,608	**1,318**	1,580	1,712
Expected return on plan assets	**(8,480)**	(8,251)	(8,306)	**(1,427)**	(1,205)	(785)
Amortization of net actuarial loss	**240**	0	0	**202**	969	1,516
Amortization of prior service cost	**414**	428	342	**279**	279	279
Amortization of transition obligation	**0**	0	0	**256**	256	256
Net periodic benefit cost	**4,143**	3,296	2,427	**1,421**	2,791	3,688
Less amounts capitalized	**841**	678	311	**288**	574	473
Net benefit costs expensed	**$3,302**	$2,618	$2,116	**$1,133**	$2,217	$3,215

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

	Pension Benefits			Postretirement Medical Benefits		
	2011	2010	2009	**2011**	2010	2009
Weighted-average discount rates	**5.75%**	6.00%	6.15%	**5.25%**	5.50%	6.05%
Expected long-term return on assets	**7.85%**	7.85%	7.85%	**7.85%**	7.85%	7.85%
Rate of increase in future compensation levels	**4.25%**	4.25%	4.25%	**4.25%**	4.25%	4.25%

2012 Cost Amortizations: The estimated amounts that will be amortized from regulatory assets and accumulated other comprehensive income into net periodic benefit cost in 2012 are as follows (dollars in thousands):

	Pension Benefits	Postretirement Medical Benefits
Actuarial loss	$908	$224
Prior service cost	328	279
Transition benefit obligation	0	192
Total	$1,236	$695

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 2011 pension and postretirement medical benefit expenses. The expected long-term rate of return on assets used to calculate these expenses for 2012 will be 7.25 percent.

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

The Pension Plan assets earned a return, net of fees, of 6.7 percent in 2011, 14.6 percent in 2010 and 25.2 percent in 2009.

Trust Fund Contributions The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. In 2011, we contributed $4.1 million to the pension trust fund and $1.6 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 2012, approximately $14 million will be paid from the Pension Plan trust fund, and $1.9 million will be paid from the postretirement medical trust funds to reimburse us for out-of-pocket benefit payments. Information about the expected cash flows for the Pension Plan and postretirement medical benefit plans is as follows (dollars in thousands):

	Pension Benefits	Postretirement Medical Benefits	
		Gross	Expected Federal Subsidy
Expected Contributions During 2012			
Employer	$5,400	$1,700	
Plan participants	n/a	$849	
Expected Benefit Payments			
2012	14,007	1,921	221
2013	8,916	2,027	236
2014	10,148	2,094	253
2015	11,308	2,086	279
2016	8,526	2,081	299
2017 - 2021	57,787	10,661	1,731

The estimated Medicare Part D subsidy included in the expected gross postretirement medical benefit payments is shown above.

Other *Long-term Disability:* We record non-accumulating post-employment long-term disability benefits in accordance with FASB's guidance for Contingencies. For 2011, the year-end post-employment benefit obligation was $1.5 million, of which $1.3 million was recorded as Accrued pension and benefit obligations and $0.2 million was recorded as Other current liabilities. For 2010, the year-end post-employment medical benefit obligation was $1.2 million, of which $1 million was recorded as Accrued pension and benefit obligations and $0.2 million was recorded as Other current liabilities. The pre-tax post-employment benefit costs charged to expense (credit), including insurance premiums, were $0.5 million in 2011, $0.2 million in 2010 and ($0.1) million in 2009.

401(k) Savings Plan: Most eligible employees choose to participate in our 401(k) Savings Plan. This savings plan provides for employee pre-tax and post-tax contributions up to specified limits. We match employee pre-tax contributions after one year of service. Eligible employees are at all times vested 100 percent in their pre-tax and post-tax contribution account and in their matching employer contribution. However, core contributions for employees after April 1, 2010 will be subject to three-year cliff vesting. Our matching contributions amounted to $1.8 million in 2011, $1.7 million in 2010 and $1.5 million in 2009.

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

For 2011, the accumulated year-end SERP benefit obligation, based on a discount rate of 4.65 percent, was $1.8 million, of which $1.6 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 2010 accumulated year-end SERP benefit obligation, based on a discount rate of 4.95 percent, was $3.6 million, of which $3.5 million was recorded as Accrued pension and benefit obligations and $0.1 million was recorded as Other current liabilities in the Consolidated Balance Sheets.

The accumulated SERP benefit obligation included a comprehensive loss of $0.1 million in 2011. The accumulated SERP benefit obligation included a comprehensive gain of $0.1 million in 2010 and an immaterial comprehensive loss in 2009. The pre-tax SERP benefit costs charged to expense totaled $0.3 million in 2011, $0.2 million in 2010 and $0.3 million in 2009.

Benefits are funded through life insurance policies held in a Rabbi Trust. Rabbi Trust assets are not considered plan assets for accounting purposes. The year-end balance included in Investments and Other Assets on our Consolidated Balance Sheets was $7.1 million in 2011 and $7 million in 2010. Rabbi Trust expenses, including changes in cash surrender value, are included in Other deductions on our Consolidated Statements of Income. The pre-tax amounts charged (credited) to expense were $0.5 million for 2011, $0.1 million for 2010, and ($0.6) million for 2009.

NOTE 17 - INCOME TAXES

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

	2011	2010	2009
Federal:			
Current	**($5,057)**	($5,268)	$250
Deferred	**7,985**	15,645	9,003
Investment tax credits, net	**(255)**	(255)	(320)
Valuation allowance	**19**	797	99
	2,692	10,919	9,032
State:			
Current	**(1,152)**	(392)	790
Deferred	**2,266**	3,924	1,134
Valuation allowance	**5**	211	(283)
	1,119	3,743	1,641
Total federal and state income taxes	**$3,811**	$14,662	$10,673
Federal and state income taxes charged to:			
Operating expenses	**$5,167**	$7,545	$5,033
Other income	**(1,356)**	7,117	5,640
	$3,811	$14,662	$10,673

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):

	2011	2010	2009
Income before income tax	**$9,515**	$35,616	$31,423
Federal statutory rate	**35.0%**	35.0%	35.0%
Federal statutory tax expense	**3,330**	12,466	10,998
Increase (benefit) in taxes resulting from:			
Dividend received deduction	**(441)**	(435)	(584)
State income taxes net of federal tax benefit	**992**	2,339	773
Investment credit amortization	**(255)**	(255)	(320)
Renewable Electricity Credit	**0**	0	(233)
AFUDC equity depreciation	**114**	112	109
Life insurance	**(67)**	(221)	(451)
Medicare Part D	**85**	653	(402)
Domestic production activities deduction	**0**	(113)	0
Valuation allowance	**19**	797	99
VY Investment	**0**	(811)	0
ASC 740 (FIN 48)	**(263)**	168	205
Return to accrual true-up	**279**	48	103
Other	**18**	(86)	376
Total income tax expense (benefit)	**$3,811**	$14,662	$10,673
Effective combined federal and state income tax rate	40.1%	41.2%	34.0%

Capitalized Repairs Project: The Capitalized Repairs Project initially included the review of 1999 through 2009 property, plant and equipment additions included in Utility Plant on the Consolidated Balance Sheets. The review was performed to identify capitalized additions, which now result in accelerated income tax deductions. During 2011, the Internal Revenue Service notified us that the Congressional Joint Committee on Taxation allowed our 2009 Capital Repairs deduction in full. Accordingly, during 2011, we received $10.4 million in federal refunds and reduced 2010 and 2011 federal and state tax expense with the remaining 2009 net operating loss carryforward. In 2011, as a result of our 2010 tax year Capitalized Repairs deduction, we recorded an additional $3.4 million to prepayments and deferred income tax liabilities on the Consolidated Balance Sheets. Also during 2011, we recorded $2.6 million to prepayments and deferred income tax liabilities on the Consolidated Balance Sheets, based upon our estimate of the 2011 tax year Capitalized Repairs deduction. As discussed in more detail below, we did not consider the establishment of an unrecorded tax benefit necessary for our 2010 and 2011 Capitalized Repairs deductions. During 2010, as a result of our 2009 tax year Capitalized Repairs deduction, excluding the impact of the related unrecorded tax benefit, we recorded $13.6 million to prepayments and $14.2 million to deferred income tax liabilities on the Consolidated Balance Sheets.

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

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

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

	2011	2010	2009
Balance at January 1	**$3,688**	$987	$1,662
Reductions from lapse of the statute of limitations			(556)
Reductions due to the passage of time/other		(56)	(119)
Settlements	**(3,497)**	(931)	
Gross amount of increase as a result of prior year tax positions	**81**		
Gross amount of increase as a result of current year tax positions		3,688	
Balance at December 31	**$272**	$3,688	$987

Included in the balance of unrecognized tax benefits at December 31, 2011, are $0.2 million of tax benefits that, if recognized, would affect the effective tax rate. The $3.5 million decrease in unrecognized tax benefits during 2011 is due to the IRS settlement of our 2009 tax year Capitalized Repairs deduction, which was allowed in full. This decrease in unrecognized tax benefits resulted in an increase in the effective tax rate due to a limitation on Vermont net operating loss carryforwards. Based upon our analysis of the audit risks associated with our 2010 and 2011 Capitalized Repairs deductions, we concluded that an additional unrecognized tax benefit was not warranted.

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

There were no unrecognized tax benefits that would affect the effective tax rate if recognized at December 31, 2009.

We recognize interest related to unrecognized tax benefits as interest expense and penalties are recorded as other deductions. For the year ended December 31, 2011, interest expense recognized on the Consolidated Statements of Income was less than $0.1 million. There was no interest expense in 2010 and a $0.1 million reversal of previously recorded interest expense in 2009. At December 31, 2011 there was less than $0.1 million of interest accrued on the Consolidated Balance Sheets. There was no accrued interest related to unrecognized tax benefits at December 31, 2010.

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

Valuation Allowance: FASB's guidance for income taxes prohibits the recognition of all or a portion of deferred income tax benefits if it is more likely than not that the deferred tax asset will not be realized. During 2010, based upon FASB income tax guidance, we recorded a $1 million deferred tax asset representing the excess of tax basis over book value for our investment in VYNPC. We also recorded an equal valuation allowance as it is more likely than not that this deferred tax asset will not be realized. There was no tax impact for this transaction.

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

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

Tax Bonus Depreciation: The Small Business Jobs Act of 2010, which became law on September 27, 2010, extended 50 percent bonus depreciation to 2010. In addition, as a result of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which became law on December 17, 2010, the 50 percent bonus depreciation was extended through 2012, and a 100 percent expensing was allowed for property placed in service after September 8, 2010 through 2011. The combined impact of the additional bonus depreciation allowed as a result of these Acts was $4.2 million in 2011 and $6.7 million in 2010. The amounts were recorded to prepayments and deferred income tax liabilities on the Consolidated Balance Sheet. These legislative changes are considered exogenous events and are included in the exogenous effects deferral. See Note 9 - Retail Rates and Regulatory Accounting for additional information.

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

	2011	2010
Deferred tax assets - current		
Reserves for uncollectible accounts	**$1,339**	$1,073
Deferred compensation and pension	**189**	906
Environmental costs accrual	**(42)**	11
Loss contingency accrual	**485**	485
Active medical accrual	**303**	270
Self insurance reserve	**500**	472
PCAM	**124**	2,086
Smart Grid	**90**	388
ASC 815 Derivatives	**2,004**	0
Federal and State NOL carryforward	**2,086**	0
Termination fee	**7,902**	0
Other accruals	**398**	407
Total deferred tax assets - current	**15,378**	6,098
Deferred tax liabilities - current		
Property tax accruals	**475**	397
Prepaid insurance	**160**	150
Derivative instruments	**2**	11
Millstone decommissioning costs	**326**	197
ESAM	**2,366**	842
Other accruals	**187**	0
Total deferred tax liabilities - current	**3,516**	1,597
Net deferred tax assets - current	**$11,862**	$4,501
Deferred tax assets - long term		
Accruals and other reserves not currently deductible	**$1,252**	$1,473
Millstone decommissioning costs	**2,411**	2,327
Contributions in aid of construction	**1,534**	1,720
Loss contingency accrual	**1,454**	1,939
Deferred compensation	**1,485**	480
Investments	**1,032**	1,008
Pension and postretirement medical liability	**13,477**	10,926
Gross deferred tax assets - long term	**22,645**	19,873
Less valuation allowance	**(1,032)**	(1,008)
Total deferred tax assets - long-term	**21,613**	18,865
Deferred tax liabilities - long term		
Property, plant and equipment	**75,960**	67,388
Benefits - regulatory asset	**15,116**	11,330
Investments	**25,916**	19,226
Other	**4,935**	3,327
Total deferred tax liabilities - long term	**121,927**	101,271
Net deferred tax liabilities - long term	**100,314**	82,406
Net deferred tax liabilities	**$88,452**	$77,905

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

	2011	2010
Total deferred tax liabilities - current and long-term	$125,443	$102,868
Less total deferred tax assets - current and long-term	36,991	24,963
Net deferred tax liabilities	$88,452	$77,905

At December 31, 2011, Federal operating loss carryforwards totaled $4.1 million and will expire on September 15, 2031. In addition, State operating loss carryforwards totaled $7.6 million and will expire on October 15, 2021. The tax effected balances of these operating loss carryforwards are recorded as current deferred income tax assets on the Consolidated Statements of Income.

NOTE 18 - COMMITMENTS AND CONTINGENCIES

Long-Term Power Purchases *Vermont Yankee:* We are purchasing our entitlement share of Vermont Yankee plant output through the VY PPA between Entergy-Vermont Yankee and VYNPC. We have one secondary purchaser that receives less than 0.5 percent of our entitlement. Our contract for purchases expires on March 21, 2012. While this has been a significant concern in the past, the short span of time before the contract's end and changes in the regional power market have decreased the risk the company might face. The New England Market currently has a significant surplus of available energy and generating capacity, and due to significant reductions in natural gas prices, electrical energy is available at competitive rates.

In recent years, prices under the VY PPA increased $1 per megawatt-hour each calendar year and were $44 per MWh in 2011 and are $45 per MWh in 2012. The VY PPA contains a provision known as the "low market adjuster" that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. Purchases in 2012 are expected to be approximately $15.6 million. The total cost estimate is based on projected MWh purchase volume at PPA rates, plus an estimate of VYNPC's costs and credits, primarily net interest, nuclear insurance refunds and administration. Actual amounts may differ. See Note 4 – Investments in Affiliates for additional information on the VY PPA.

A summary of the VY PPA, including the actual amount for 2011 and the estimated average amount 2012, is shown in the table below. The total cost estimate is based on projected MWh purchase volume at PPA rates, plus an estimate of VYNPC's costs and credits, primarily net interest, nuclear insurance refunds and administration. Actual amounts may differ.

	2011	Estimated Average 2012
Average capacity acquired	180	180
Share of VYNPC entitlement	34.80%	34.80%
Annual energy charge per MWh	$44.12	$45.15
Average total cost per MWh	$43.92	$45.86
Contract period termination	March 2012	

Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. We purchase replacement energy as needed when the Vermont Yankee plant is not operating or is operating at reduced levels. We typically acquire most of this replacement energy through forward purchase contracts and account for those contracts as derivatives. Our total VYNPC purchases were $62.4 million in 2011, $58.7 million in 2010 and $64 million in 2009.

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

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

On January 10, 2012, after failing to reach a resolution of the matter with Entergy-Vermont Yankee, we and GMP filed a lawsuit in Vermont Superior Court in Windham County. The lawsuit seeks compensatory damages of $6.6 million to cover increased power costs and lost capacity payments resulting from the tower failures, plus interest. Our portion of this claim is $4.3 million. On January 18, 2012, Defendant Entergy-Vermont Yankee filed a notice of removal of the case to the United States District Court for the District of Vermont, asserting diversity of citizenship and federal jurisdiction over a federal question. The defendant also filed an answer to the complaint, and asserted affirmative defenses and demanded a jury trial. The case is now pending in the federal court. We cannot predict the outcome of this matter at this time.

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

Coincident with the termination of the VY PPA on March 21, 2012 is the termination of the Vermont Yankee plant's original 40-year operating license. While the NRC voted 4-0 to approve the 20-year license extension through March 21, 2032 requested by Entergy-Vermont Yankee, under Act 160, a Vermont law enacted in 2006, a favorable Vermont legislative vote was required for the Vermont Yankee plant to continue operations after March 21, 2012. 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.

In a federal lawsuit filed in U.S. District Court for the District of Vermont on April 18, 2011, Entergy-Vermont Yankee contended that the state was improperly attempting to interfere with its relicensing and sought a judgment to prevent the state of Vermont from forcing the Vermont Yankee nuclear power plant to cease operation on March 21, 2012. The complaint sought both declaratory and injunctive relief, and contended that Vermont's attempts to close the plant are preempted by the Atomic Energy Act, the Federal Power Act and the Commerce Clause of the U.S. Constitution.

During the week of September 12, 2011, the U.S. District Court for the District of Vermont held a trial on the merits of Entergy-Vermont Yankee's complaint.

On January 19, 2012 the U.S. District Court for the District of Vermont issued a decision ruling against the state of Vermont. The effect of the ruling is that the state is prohibited under federal law from taking any action to compel the plant to shut down after March 21, 2012 because it failed to obtain legislative approval (under the provisions of Act 160). The state of Vermont was precluded from shutting the plant down for safety-related reasons. On February 18, 2012, the state filed a notice of appeal with the 2nd U.S. Circuit Court of Appeals in New York. Meanwhile, Vermont Yankee still must obtain a Certificate of Public Good from the PSB to gain a 20-year license extension. We are participants in this docket due to a prior revenue-sharing agreement. That revenue-sharing arrangement provides in part that in the event that Entergy extends the operation of the plant pursuant to an extension of its NRC license, Entergy agrees to share with VYNPC 50 percent of the "Excess Revenue" for 10 years commencing on March 13, 2012.

On February 27, 2012, Entergy filed notice with the U.S. District Court for the District of Vermont saying that it would ask the 2nd U.S. Circuit Court of Appeals to review a decision. It will appeal a federal judge's order allowing the plant to stay open past its originally scheduled shutdown date, and will ask the original judge to revisit his order and prevent the state of Vermont from barring the future storage of spent nuclear fuel at the plant. Entergy has informed the PSB that it intends to continue to operate the plant pending a final PSB ruling on its operation. The PSB has not yet indicated whether it will require the plant to cease operations after March 21.

Hydro-Québec: We continue to purchase power under the Hydro-Québec VJO power contract. The VJO power contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between us and Hydro-Québec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO power contract runs through 2020, but our purchases under the contract end in 2016. The average level of deliveries under the current contract decreases by approximately 20 percent after 2012, and by approximately 84 percent after 2015.

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

There are two sellback contracts with provisions that apply to existing and future VJO power contract purchases. The first resulted in the sellback of 25 MW of capacity and associated energy through April 30, 2012, which has no net impact currently since an identical 25 MW purchase was made in conjunction with the sellback. We have a 23 MW share of the 25 MW sellback. However, since the sellback ends six months before the corresponding purchase ends, the first sellback will result in a 23 MW increase in our capacity and energy purchases for the period from May 1, 2012 through October 31, 2012.

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Québec. The first option was never exercised and expired December 31, 2010. The second gives Hydro-Québec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Québec. This second option can be exercised five times through October 2015 but due to the notice provision there is a maximum remaining application of three times available. To date, Hydro-Québec has not exercised this option. We have determined that this second option is not a derivative because it is contingent upon a physical variable.

There are specific contractual provisions providing that in the event any VJO member fails to meet its obligation under the contract with Hydro-Québec, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2011, our obligation is about 47 percent of the total VJO power contract through 2016, and represents approximately $226.8 million, on a nominal basis.

In accordance with FASB's guidance for guarantees, we are required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. With regard to the "step-up" provision in the VJO power contract, we must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. We believe this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power contract in its most recent rate applications. Despite the remote chance that such an event could occur, we estimate that our undiscounted purchase obligation would be an additional $265.2 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2012 and remained in default for the duration of the contract. In such a scenario, we would then own the power and could seek to recover our costs from the defaulting members or our retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

Total purchases from Hydro-Québec were $61.9 million in 2011, $63 million in 2010 and $63.1 million in 2009. Annual capacity costs decreased by $2.2 million starting November 1, 2009, and that cost reduction will continue for six contract years. An additional annual $0.9 million capacity cost reduction started November 1, 2011, of which $0.4 will continue for five contract years. A summary of the Hydro-Québec actual charges for 2011 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	
	2011	2012	2013 -2016
Annual Capacity Acquired	**143.8**	152.8	(a)
Minimum Energy Purchase - annual load factor (b)	**75%**	75%	75%
Energy Charge	**$29,786**	$33,540	$20,032
Capacity Charge	**32,147**	33,570	19,886
Total Energy and Capacity Charge	**$61,933**	$67,110	$39,918
Average Cost per kWh	**$0.070**	$0.067	$0.069

(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 IPPs, primarily so-called small power producers. 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. Starting in 2012, we will also purchase power from some larger independent producers, primarily wind projects. Estimated annual purchases are expected to increase from $23.5 million in 2011 to about $35 million in 2012 and up to $47 million by 2016. These cost estimates are based on assumptions regarding the number, sizes and types of IPPs that we purchase from, hydrological and wind conditions and other factors, so actual amounts could be higher or lower. Our total purchases from IPPs were $23.5 million in 2011, $22.9 million in 2010 and $22.6 million in 2009.

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):

	2011			
	Gross Investment	Accumulated Depreciation	Net Investment	Plant Under Construction
Wyman #4	$3,876	$3,231	$644	$32
Joseph C. McNeil	18,521	14,076	4,445	3
Millstone Unit #3	79,027	43,146	35,881	1,441
Highgate Transmission Facility	14,577	9,388	5,189	4,087
	$116,001	$69,841	$46,159	$5,563

	2010			
	Gross Investment	Accumulated Depreciation	Net Investment	Plant Under Construction
Wyman #4	$3,853	$3,121	$732	$32
Joseph C. McNeil	18,270	13,458	4,812	47
Millstone Unit #3	78,929	42,213	36,716	1,333
Highgate Transmission Facility	14,696	9,438	5,258	12
	$115,748	$68,230	$47,518	$1,424

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

We have a 1.7303 joint-ownership percentage in Millstone Unit #3, in which DNC is the lead owner with 93.4707 percent of the plant joint-ownership. In January 2004 DNC filed, on behalf of itself and the two minority owners, including us, a lawsuit against the DOE seeking recovery of costs related to the storage of spent nuclear fuel arising from the failure of the DOE to comply with its obligations to commence accepting such fuel in 1998. A trial commenced in May 2008. On October 15, 2008, the United States Court of Federal Claims issued a favorable decision in the case, including damages specific to Millstone Unit #3. The DOE appealed the court's decision in December 2008. On February 20, 2009, the government filed a motion seeking an indefinite stay of the briefing schedule. On March 18, 2009, the court granted the government's request to stay the appeal. On November 19, 2009, DNC filed a motion to lift the stay. On April 12, 2010, the stay was lifted and a staggered briefing schedule was proposed, to which DNC has responded with a request to expedite the briefing schedule so that the appeals of all parties can be heard concurrently.

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

On April 25, 2011 the U.S. Court of Appeals for the Federal Circuit issued a decision affirming the spent fuel damages award for damages incurred through June 30, 2006 in connection with DOE's failure to begin accepting spent fuel for disposal. The government had the option to seek rehearing of the Federal Circuit decision and to seek review by the U.S. Supreme Court. The time period for seeking rehearing was 45 days.

On June 30, 2011, DNC informed us that the DOE decided not to seek rehearing and instead wishes to pay the awarded damages. In October 2011 we received $0.2 million and the amount was credited to our retail customers.

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

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

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

On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. Technical hearings were held and final legal briefs were filed in the first quarter of 2011. On April 15, 2011, the PSB issued an order approving the HQUS PPA.

Under the HQUS PPA, we are entitled to purchase an energy quantity of up to 5 MW from November 1, 2012 to October 31, 2015; 90.4 MW from November 1, 2015 to October 31, 2016; 101.4 MW from November 1, 2016 to October 31, 2020; 103.4 MW from November 1, 2020 to October 31, 2030; 112.8 MW from November 1, 2030 to October 31, 2035; and 27.4 MW from November 1, 2035 to October 31, 2038. These quantities include assumption of Vermont Marble's allocations as a result of our September 1, 2011 purchase of Vermont Marble.

Other Future Power Agreements: As we continue to build and diversify our power portfolio as planned and to comply with state law which establishes goals for including renewable power in our mix, we have signed several agreements for clean and competitively priced renewable energy. On September 9, 2010 we agreed to terms for purchasing output over nine years from Iberdrola Renewables' planned Deerfield Wind Project. The agreement was signed by the parties on December 13, 2010. The project has experienced delays in receiving a necessary permit from the U.S. Forest Service and construction is not now scheduled to take place in a manner that would be sufficient for meeting the conditions precedent of the agreement. The developer received the permit, but it was too late for completion of the project in 2012, and the project is now on hold. Conditions precedent not satisfied or waived on or before April 1, 2012 could result in termination of the contract by June 30, 2012. We are currently in discussions with Iberdrola, the parent company, with respect to terminating, reforming or replacing the agreement.

Other agreements signed in 2010 include: two separate agreements to purchase 30.3 percent of the actual output from Granite Reliable Wind project for 20 years beginning April 1, 2012 and an additional 20 percent for 15 years beginning in November 2012; an agreement to purchase the entire 4.99 MW output of Ampersand Gilman Hydro for five years starting April 1, 2012; and 15 MW of around-the-clock energy from J.P. Morgan Ventures Energy for the calendar years 2013 through 2015.

On July 27, 2011, in cooperation with an energy management firm, we conducted a highly structured Internet auction that involved a dozen pre-screened northeastern generators and energy marketers. When the bidding closed, we signed three contracts with an average price of approximately $47.50 per megawatt-hour, or 4.75 cents per kilowatt-hour.

Two of the contracts will fill the 2012 gap in our portfolio created by the end of our existing contract with Vermont Yankee. One will supply energy 24 hours per day from April 1, 2012 through the end of the year, while the other will provide both peak and off-peak power during specific periods in 2012 when we have remaining supply gaps. The third contract filled our energy needs during the planned Vermont Yankee refueling outage that ended November 3, 2011.

These purchase contracts will provide about 570,000 megawatt-hours of energy or about 20 percent of our power supply during the life of the contracts, for $27 million. The contracts are for so-called "system power," meaning they are not conditioned on the operation of individual power generation sources.

In September 2011, we also used the auction process to sell small amounts of projected excess energy to hedge price risks during the first two months of 2012.

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

We have equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down and completely decommissioned except for the spent fuel storage at each location. Our obligations related to these plants are described in Note 4 - Investments in Affiliates.

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

Nuclear Insurance The Price-Anderson Act provides a framework for immediate, no-fault insurance coverage for the public in the event of a nuclear power plant accident that is deemed an "extraordinary nuclear occurrence" by the NRC. The EPACT reinstated and extended the Price-Anderson Act for 20 years. There are two levels of coverage. The primary level provides liability insurance coverage of $375 million, or the maximum private insurance available. If this amount is not sufficient to cover claims arising from an accident, the second level applies offering additional coverage up to $12.6 billion per incident. For the second level, each operating nuclear plant must pay a retrospective premium equal to its proportionate share of the excess loss, up to a maximum of $111.9 million per reactor per incident, limited to a maximum annual payout of $17.5 million per reactor. These assessments will be adjusted for inflation and U.S. Congress can modify or increase the insurance liability coverage limits at any time through legislation. Currently, based on our joint-ownership interest in Millstone Unit #3, we could become liable for about $0.3 million of such maximum assessment per incident per year. Maine Yankee, Connecticut Yankee and Yankee Atomic maintain $100 million in Nuclear Liability Insurance, but have received exemptions from participating in the secondary financial protection program.

Performance Assurance We are subject to performance assurance requirements through ISO-NE under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $3 million with ISO-NE. We are required to post collateral for all net power and transmission 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, 2011, we had posted $3.9 million of collateral under performance assurance requirements for certain of our power and transmission transactions, $3.5 million of which was represented by a letter of credit and $0.4 million of which was represented by cash and cash equivalents. At December 31, 2010, we had posted $6.6 million of collateral under performance assurance requirements for certain of our power and transmission transactions, $5.5 million of which was represented by a letter of credit and $1.1 million of which was represented by cash and cash equivalents.

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 EPA. We believe that we are in compliance with all laws and regulations and have implemented procedures and controls to assess and assure compliance. Corrective action is taken when necessary.

As of December 31, 2011, our Environmental Reserve was $0.3 million, compared to $0.8 million in 2010 and $1.6 million in 2009. A summary of the Environmental Reserve as of December 31 follows (dollars in thousands):

	2011	2010	2009
Environmental reserve balance at beginning of year	**$836**	$1,565	$1,732
Charged to income and expenses	**317**	838	
Deductions	**(805)**	(1,567)	(167)
Environmental reserve balance at end of year	**$348**	$836	**$1,565**

The reserve for environmental matters is included in current liabilities on the Consolidated Balance Sheets and represents our best estimate of the cost to remedy issues at these sites based on available information as of the end of the applicable reporting periods. Below is a brief discussion of the significant sites for which we have recorded reserves.

Cleveland Avenue Property: The Cleveland Avenue property in Rutland, Vermont, was used by a predecessor to make gas from coal. Later, we sited various operations there. Due to the existence of coal tar deposits, PCB contamination and the potential for off-site migration, we conducted studies in the late 1980s and early 1990s to quantify the nature and extent of contamination and potential costs to remediate the site. Investigation at the site continued, including work with the State of Vermont to develop a mutually acceptable solution. In June 2010, both the VANR and the EPA approved separate remediation work plans for the manufactured gas plant and PCB waste at the site. Remedial work started in August 2010 and concluded in early December 2010. It was necessary to increase the reserve by $0.3 million in the first quarter of 2011. In February 2011, we submitted a Construction Completion Report for the project to the EPA and VANR for review. The report documented remedial construction and confirmatory sampling activities. Some additional site work, including final grading and vegetation planting, occurred during the third quarter of 2011, and the site sustained some minor flood damage from Tropical Storm Irene. As of December 31, 2011, there was no remaining obligation.

Brattleboro Manufactured Gas Facility: In the 1940s, we owned and operated a manufactured gas facility in Brattleboro, Vermont. We ordered a site assessment in 1999 at the request of the State of New Hampshire. In 2001, New Hampshire indicated that no further action was required, although it reserved the right to require further investigation or remedial measures. In 2002, the VANR notified us that our corrective action plan for the site was approved. As of December 31, 2011, our estimate of the remaining obligation is $0.3 million.

The Windham Regional Commission and the Town of Brattleboro are currently pursuing the redevelopment of the gas plant site and waterfront area into vehicle parking with green space. This concept calls for the removal of the remnant gas plant building plus covering and otherwise avoiding contaminated areas instead of removing contaminated soil and debris.

Throughout 2010, we discussed the proposed redevelopment with consultants for the Town of Brattleboro and the Windham Regional Commission. We expressed a willingness to enter into a formal remediation agreement with the Town of Brattleboro governing the redevelopment of the site.

We met with the Town of Brattleboro in 2011 and we agreed to an Amended and Restated Grant of Environmental Restrictions for the gas plant property. In November 2011, we contributed $0.2 million toward the remediation project. We will monitor site remediation and construction in 2012 and reassess the reserve to determine if an adjustment is necessary.

Dover, New Hampshire, Manufactured Gas Facility: In 1999, PSNH contacted us about this site. PSNH alleged that we were partially liable for cleanup, since the site was previously operated by Twin State Gas and Electric, which merged into CVPS on the same day that PSNH bought the facility. In 2002, we reached a settlement with PSNH in which certain liabilities we might have had were assigned to PSNH in return for a cash settlement we paid over time based on completion of PSNH's cleanup effort and periodic monitoring. In December 2011, we made the final settlement payment. As of December 31, 2011, there was no remaining obligation.

Middlebury Lower Substation: By letter dated February 5, 2010, the VANR Sites Management Section informed us they require additional investigation of the soil contamination at the Middlebury Lower Substation. This was a result of voluntarily submitted information from internal soil sampling that we completed in the fall of 2009. The soil sampling showed elevated levels of TPH that required remediation. The contaminated soil and concrete was removed in conjunction with the reconstruction of the substation in 2011. As of December 31, 2011, there was no remaining obligation.

Salisbury Substation: We completed internal testing and found PCBs and TPH, in addition to small quantities of pesticides in the soil and concrete at this site. The substation is located adjacent to the Salisbury hydroelectric power station. It is scheduled to be retired and replaced during 2011. Final results indicated that PCB, TPH and pesticide concentrations exceed state and federal regulatory limits on portions at the site. In late 2011 and early 2012, we removed the contaminated material from the site in accordance with VT ANR and EPA-approved remediation plans. We submitted a letter to the VANR Sites Management Section proposing that PCB remediation efforts would be sufficient mitigation for TPH and pesticide contamination, and proposed to collect soil samples for confirmatory testing of these compounds. As of December 31, 2011, our estimate of the remaining obligation is less than $0.1 million.

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

Catamount Indemnifications On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm. Under the terms of the agreements with Catamount and Diamond Castle Holdings, we agreed to indemnify them, and certain of their respective affiliates, in respect of a breach of certain representations and warranties and covenants, most of which ended June 30, 2007, except certain items that customarily survive indefinitely. Indemnification is subject to a $1.5 million deductible and a $15 million cap, excluding certain customary items. Environmental representations are subject to the deductible and the cap, and such environmental representations for only two of Catamount's underlying energy projects survived beyond June 30, 2007. Our estimated "maximum potential" amount of future payments related to these indemnifications is limited to $15 million. We have not recorded any liability related to these indemnifications. To management's knowledge, there is no pending or threatened litigation with the potential to cause material expense. No government agency has sought funds from us for any study or remediation.

Leases and support agreements *Capital Leases:* We had obligations under capital leases of $3.4 million at December 31, 2011 and $4.4 million at December 31, 2010. 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 Statement of Operations, depending on the nature and function of the leased assets. Of the $3.4 million in 2011, $3.3 million is related to the Hydro-Québec Phase II transmission facilities and the remaining $0.1 million is related to several five-year office and computing equipment leases.

We participated with other electric utilities in the construction of the Phase II transmission facilities in New England, which were completed at a total initial cost of $487 million. Under a 30-year support agreement relating to participation in the facilities, we agreed to pay our 5.132 percent share of Phase II costs, including capital costs plus the costs of owning and operating the facilities, over a 25-year recovery period that ends in 2015, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2020. Approximately $33 million of additional investments have been made to the Phase II transmission facilities since they were initially constructed. All costs under these agreements are recorded as transmission expense in accordance with our ratemaking policies. At December 31, 2011, the $3.3 million unamortized balance was comprised of $19.2 million related to our share of original costs and additional investments, offset by $15.9 million of accumulated amortization.

We also participated with other electric utilities in the construction of the Hydro-Québec Phase I transmission facilities in northeastern Vermont and northern New Hampshire, which were completed at a total cost of $140 million. Under the 30-year support agreement relating to participation in the facilities, we were obligated to pay our 4.55 percent share of Phase I capital costs over a 20-year recovery period that ended in 2006, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2016. At December 31, 2011, we had recorded accumulated amortization of $4.9 million representing our share of the original costs associated with the Phase I transmission facility. Our Phase I share increased to 4.66 percent effective September 1, 2011 due to the purchase of Vermont Marble.

The Phase I and Phase II support agreements provide options for extending the agreements an additional 20 years. Each option must be exercised two years before each agreement terminates, and the transmission facilities for Phase I and Phase II must operate simultaneously for the interconnection to operate, therefore both agreements would need to be extended to be operative. Future annual payments relating to the Phase I and Phase II transmission facilities are expected to decline from $3 million in 2012 to $2.3 million in 2016. If we elect to extend both agreements, annual payments are generally expected to continue declining past the 2020 renewal year, unless unforeseen equipment failures occur. Approximately $0.5 million of the annual costs are currently reimbursed to us pursuant to the ISO-NE Open Access Transmission Tariff.

For the year ended December 31, 2011, imputed interest on capital leases totaled $0.3 million. A summary of minimum lease payments as of December 31, 2011 follows (dollars in thousands).

Year	Capital Leases
2012	$1,171
2013	1,085
2014	954
2015	738
2016	0
Future minimum lease payments	3,948
Less: amount representing interest	(560)
Present value of net minimum lease payments	$3,388

Operating Leases: We have two master lease agreements for vehicles and related equipment. On October 30, 2009, we signed a vehicle lease agreement to finance many of the vehicles covered by a former agreement. Our guarantee obligation under this lease will not exceed 8 percent of the acquisition cost. The maximum amount of future payments under this guarantee at December 31, 2011 is approximately $0.3 million. The total future minimum lease payments required for all lease schedules under this agreement at December 31, 2011 is $2.2 million. As of December 31, 2011 there is no credit line in place for additions under this agreement. The total acquisition cost of all lease additions under this agreement at December 31, 2011 was $4.1 million. At December 31, 2010, the total acquisition cost of all lease additions under this agreement was $5.3 million.

On October 24, 2008, we entered into an operating lease for new vehicles and other related equipment. Our guarantee obligation under this lease is limited to 5 percent of the acquisition cost. The maximum amount of future payments under this guarantee is approximately $0.1 million. The total future minimum lease payments required for all lease schedules under this agreement at December 31, 2011 is $1.7 million. As of December 31, 2011 there is no credit line in place for additions under this agreement. The total acquisition cost of all lease additions under this agreement at December 31, 2011 and 2010 was $2.9 million.

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

At December 31, 2011, future minimum rental payments required under non-cancelable operating leases are expected to total $3.6 million, consisting of $1.4 million in 2012, $1.2 million in 2013, $0.7 million in 2014, $0.3 million in 2015, and $0 million thereafter.

Total rental expense, which includes pole attachment rents in addition to the operating lease agreements described above, amounted to $6.1 million in 2011 and 2010 and $6.3 million in 2009. These are included in Other operation on the Consolidated Statements of Income.

Merger Agreement with Gaz Métro The Merger Agreement contains certain termination rights for both CVPS and Gaz Métro and further provides that upon termination of the merger agreement under specified circumstances, CVPS may be required to pay Gaz Métro a termination fee of $17.5 million and reimburse Gaz Métro for up to $2 million of its reasonable out-of-pocket transaction expenses. Also, see Note 2 - Summary of Significant Accounting Policies to the accompanying Notes to Consolidated Financial Statements.

Reserve for Loss on Power Contract In 2004, we established a reserve for a loss on a terminated power sales agreement in connection with the sale of a subsidiary's franchise. The reserve is being amortized on a straight-line basis through 2015 as the cash is paid out under the underlying supply contracts. The amortization is being credited to purchased power expense on the Consolidated Statement of Income. The balance of the reserve was $4.8 million in December 31, 2011 and $6 million at December 31, 2010. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets.

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

Legal Proceedings We are involved in legal and administrative proceedings, including civil litigation, in the normal course of business as well as a number of lawsuits relating to our pending merger agreement with Gaz Métro that are described in Note 1 – Business Organization, Litigation Related to Merger Agreement. We are unable to fully determine a range of reasonably possible court-ordered damages, settlement amounts, and related litigation costs or legal liabilities that would be in excess of amounts accrued and amounts covered by insurance. Based on the information currently available, we do not believe that it is probable that any such legal liability will have a material impact on our consolidated financial position. It is reasonably possible that additional legal liabilities that may result from changes in estimates could have a material impact on our results of operations, financial condition 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 at December 31, 2011 and December 31, 2010.

NOTE 19 – ACQUISITIONS

Vermont Marble Power Division: On June 10, 2011, the PSB issued an order approving our purchase of the Vermont Marble Power Division of Omya, Inc., pursuant to the purchase and sale agreement and issued a Certificate of Consent. On September 1, 2011, we closed on the transaction. Included in the sale are rights to serve approximately 875 customers, including the Omya industrial facility, which became our single-largest customer representing approximately 6 percent of expected future annual retail sales. The acquisition will create efficiencies that will reduce costs and benefit customers overall; and we acquired renewable hydro assets at competitive costs for our customers.

The agreement also includes a five-year, six-step phase-in of residential rate changes for existing Vermont Marble customers, which will be funded by Omya up to an amount estimated to be approximately $1.1 million.

We will be allowed recovery from customers of up to $27 million for the generating assets and $0.8 million for the transmission and distribution assets. The MOU also requires the creation of a so-called value sharing pool that provides for certain excess value we receive, if any, to be shared among our customers, Omya and our shareholders if energy market prices and hydro facility improvements create more value than anticipated for a period of 15 years following the closing date. This will provide us with an opportunity to recover up to $1.3 million not otherwise recovered in rates.

We plan to invest an estimated $20 million between 2012 and 2015 to upgrade the Vermont Marble facilities.

The actual revenues of Vermont Marble from the acquisition date through December 31, 2011 were approximately $6.3 million. If the Vermont Marble acquisition closed on January 1, 2010, the incremental revenues on a pro forma basis would be $16.5 million for the 12 months ended December 31, 2010 and $19 million for the 12 months ended December 31, 2011.

Our actual earnings related to the purchase of Vermont Marble from the acquisition date through December 31, 2011 were approximately $0.4 million. If the Vermont Marble acquisition closed on January 1, 2010, the incremental earnings on a pro forma basis would be $0.1 million for the 12 months ended December 31, 2010 and $1.3 million for the 12 months ended December 31, 2011. In 2011, we incurred $0.1 million of acquisition-related costs that were recorded in the Consolidated Statements of Income.

Our primary valuation technique to measure the fair value of the assets shown below at the acquisition date is based on the income approach. This is due to the regulatory treatment of utility-related assets.

The fair value allocations of the Vermont Marble acquisition are as follows (dollars in thousands):

Fair value of business combination:	
Cash payments	$29,743
Total	**$29,743**
Identifiable assets acquired:	
Utility plant, net of accumulated depreciation	$27,620
Accounts receivable	151
Other deferred charges – regulatory	658
Other deferred charges and other assets	1,972
Total	**$30,401**
Liabilities Assumed:	
Power-related derivatives	$658
Total	**$658**

We are reporting the operations for this acquisition within the results of our CV-VT segment from the acquisition date.

Readsboro Electric Department: On October 27, 2010, we signed a purchase and sale agreement with Readsboro. The $0.4 million purchase price includes all of the assets of Readsboro including about 14 miles of distribution line and associated equipment, and the exclusive franchise Readsboro holds to serve its 310 customers. On February 24, 2011 we, along with the DPS and Readsboro, filed a stipulation with the PSB that resolves the issues outstanding in our acquisition of Readsboro. On July 8, 2011, the PSB issued an order approving the purchase and sale agreement, and issued a Certificate of Consent. The PSB order does not allow us to recover the acquisition premium of $0.1 million, which is the amount above the net book value of $0.3 million, which approximates fair value. We also assumed a nominal amount of liabilities. On August 1, 2011, we closed on the transaction.

NOTE 20- SEGMENT REPORTING

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

The accounting policies of operating segments are the same as those described in Note 2 - Summary of Significant Accounting Policies. All segment operations are managed centrally by CV - VT. Segment profit or loss is based on net income. Other Companies are below the quantitative thresholds individually and in the aggregate.

2011	CV VT	Other Companies	Reclassification and Consolidating Entries	Consolidated
Revenues from external customers	$359,734	$1,696	($1,696)	$359,734
Depreciation and amortization (a)	$15,450	$223	($223)	$15,450
Operating income tax expense	$5,167	$118	($118)	$5,167
Equity in earnings of affiliates	$27,733	$0	$0	$27,733
Interest income (b)	$64	$2	$0	$66
Interest expense	$13,652	$0	$0	$13,652
Net income	$5,531	$173	$0	$5,704
Investments in affiliates	$179,974	$0	$0	$179,974
Total assets	$773,557	$2,949	($241)	$776,265
Construction and plant expenditures (c)	$41,129	$360	$0	$41,489

2010				
Revenues from external customers	$341,925	$1,731	($1,731)	$341,925
Depreciation and amortization (a)	$15,038	$189	($189)	$15,038
Operating income tax expense	$7,545	$278	($278)	$7,545
Equity in earnings of affiliates	$21,098	$0	$0	$21,098
Interest income (b)	$183	$2	$0	$185
Interest expense	$11,560	$0	$0	$11,560
Net income	$20,526	$428	$0	$20,954
Investments in affiliates	$171,514	$0	$0	$171,514
Total assets	$707,973	$3,019	($246)	$710,746
Construction and plant expenditures (c)	$33,021	$290	$0	$33,311
2009				
Revenues from external customers	$342,098	$1,731	($1,731)	$342,098
Depreciation and amortization (a)	$17,070	$214	($214)	$17,070
Operating income tax expense	$5,033	$303	($303)	$5,033
Equity in earnings of affiliates	$17,472	$0	$0	$17,472
Interest income (b)	$99	($22)	$0	$77
Interest expense	$11,600	($118)	$0	$11,482
Net income	$19,908	$841	$0	$20,749
Investments in affiliates	$129,733	$0	$0	$129,733
Total assets	$630,103	$2,356	($307)	$632,152
Construction and plant expenditures (c)	$31,413	$386	$0	$31,799

(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 21 - 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)
2011					
Operating revenues	**$97,085**	**$84,268**	**$88,051**	**$90,330**	**$359,734**
Utility operating income	**$6,928**	**$1,227**	**$4,425**	**$3,773**	**$16,353**
Net income	**$8,425**	**$736**	**($8,646)**	**$5,189**	**$5,704**
Basic earnings per share	**$0.62**	**$0.05**	**($0.65)**	**$0.38**	**$0.40**
Diluted earnings per share	**$0.62**	**$0.05**	**($0.65)**	**$0.38**	**$0.40**
2010					
Operating revenues	$91,007	$79,937	$85,392	$85,589	$341,925
Utility operating income	$3,255	$1,103	$8,629	4,468	$17,455
Net income	$4,202	$1,445	$9,990	$5,317	$20,954
Basic earnings per share	$0.35	$0.11	$0.79	$0.40	$1.66
Diluted earnings per share	$0.35	$0.11	$0.79	$0.40	$1.66

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

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Management of the company, under the supervision and with participation of our Principal 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, 2011. Based on this evaluation, our Principal Executive Officer and Principal Financial and Accounting Officer concluded that, as of December 31, 2011, the company's disclosure controls and procedures are effective.

Disclosure controls and procedures are designed to ensure that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed under the Exchange Act is accumulated and communicated to management, including the principal executive and financial officers, as appropriate to allow timely decisions regarding required disclosure. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

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 Exchange Act. 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 Principal 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, 2011.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements, included in this Annual Report, has issued an attestation report on our internal control over financial reporting, which report is included below.

Changes in Internal Control over Financial Reporting There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our 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, 2011, 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, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Company and our report dated March 14, 2012, which report expressed an unqualified opinion on those consolidated financial statements and refers to the reports of other auditors.

/S/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 14, 2012

Item 9B. Other Information
None

PART III

Item 10. Directors, Executive Officers and Corporate Governance.
The information required by this item will be included in our Proxy Statement relating to our 2012 Annual Meeting of Shareholders and is incorporated herein by reference. However, if the Proxy Statement is not filed within 120 days of the Company's fiscal year ended December 31, 2011, the disclosure will be provided in an amendment to this 10-K.

Item 11. Executive Compensation.
The information required by this item will be included in our Proxy Statement relating to our 2012 Annual Meeting of Shareholders and is incorporated herein by reference. However, if the Proxy Statement is not filed within 120 days of the Company's fiscal year ended December 31, 2011, the disclosure will be provided in an amendment to this 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.
The information required by this item will be included in our Proxy Statement relating to our 2012 Annual Meeting of Shareholders and is incorporated herein by reference. However, if the Proxy Statement is not filed within 120 days of the Company's fiscal year ended December 31, 2011, the disclosure will be provided in an amendment to this 10-K.

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	33,948	$20.57	-
2000 Stock Option Plan for Key Employees	96,880	$18.39	-
Omnibus Stock Plan	99,592	$20.18	80,374
Total	**230,420**	**$19.485**	**80,374**

Item 13. Certain Relationships and Related Transactions, and Director Independence.
The information required by this item will be included in our Proxy Statement relating to our 2012 Annual Meeting of Shareholders and is incorporated herein by reference. However, if the Proxy Statement is not filed within 120 days of the Company's fiscal year ended December 31, 2011, the disclosure will be provided in an amendment to this 10-K.

Item 14. Principal Accounting Fees and Services.
The information required by this item will be included in our Proxy Statement relating to our 2012 Annual Meeting of Shareholders and is incorporated herein by reference. However, if the Proxy Statement is not filed within 120 days of the Company's fiscal year ended December 31, 2011, the disclosure will be provided in an amendment to this 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

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

Consolidated Statements of Income for the three years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Comprehensive Income for the three years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Cash Flows for the three years ended December 31, 2011, 2010 and 2009

Consolidated Balance Sheets at December 31, 2010 and 2009

Consolidated Statements of Changes in Common Stock Equity at December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements

(a)2. Required information related to Schedule II - Reserves for the three years ended December 31, 2011, 2010 and 2009 is included herein under Part II, Item 8, Financial Statements and Supplementary Data, Notes to Consolidated Financial Statements

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

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

* - Filed herewith.

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

Exhibit 2 Plan of acquisition, reorganization, arrangement, liquidation or succession

2-1 Agreement and Plan of Merger, dated as of May 27, 2011, by and among FortisUS Inc., Cedar Acquisition Sub Inc., Central Vermont Public Service Corporation, and, solely for the purposes of Section 8.15 thereof, Fortis Inc. (Exhibit No. 2.1, Current Report on Form 8-K Filed May 31, 2011, File No. 1-8222)

2-1 Agreement and Plan of Merger, dated as of July 11, 2011, by and among Gaz Métro Limited Partnership, Danaus Vermont Corp., and Central Vermont Public Service Corporation. (Exhibit No. 2.1, Current Report on Form 8-K Filed July 12, 2011, File No. 1-8222)

Exhibit 3 Articles of Incorporation and By-laws

3-1 By-laws, as amended February 27, 2012. (Exhibit 99.2, Current Report on Form 8-K Filed March 2, 2012, File No. 1-8222)

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

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

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

Incorporated herein by reference:

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

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

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

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

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

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

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

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

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

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

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

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

4-13 Forty-Eighth Supplemental Indenture, dated as of June 15, 2011, from the Company to U.S. Bank National Association, as trustee. (Exhibit 4-13, Current Report on Form 8-K Filed June 16, 2011, File No. 1-8222)

Exhibit 10 Material Contracts (* Denotes filed herewith)

Incorporated herein by reference:

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

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

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

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

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

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

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

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

10.3.1 Copies of Amendments dated September 7, 1961, November 2, 1967, March 22, 1968, and October 29, 1968. (Exhibit C-6, File No. 2-32917)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10.18.6 Amendment to the Power Contract between the Company and Yankee Atomic Electric Company dated October 1, 1980. (Exhibit 10.25.6, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.7 Amendment No. 3 to the Power Contract between the Company and Yankee Atomic Electric Company dated April 1, 1985. (Exhibit 10.25.7, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.8 Amendment No. 8 to the Power Contract between the Company and Yankee Atomic Electric Company dated June 1, 2003. (Exhibit 10.25.8, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.9 Amendment No. 9 to the Power Contract between the Company and Yankee Atomic Electric Company dated November 17, 2005. (Exhibit 10.25.9, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.10 Amendment No. 10 to the Power Contract between the Company and Yankee Atomic Electric Company dated April 14, 2006. (Exhibit 10.25.10, Form 10-Q, September 30, 2006, File No. 1-8222)

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

10.20 Copy of Power Contract between the Company and Connecticut Yankee dated as of June 1, 1964. (Exhibit C-64, 1981 Form 10-K, File No. 1-8222)

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

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

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

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

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

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

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

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

10.21 Copy of Transmission Contract between the Company and Connecticut Yankee dated as of July 1, 1964. (Exhibit C-65, 1981 Form 10-K, File No. 1-8222)

10.22 Copy of Capital Funds Agreement between the Company and Connecticut Yankee dated as of July 1, 1964. (Exhibit C-66, 1981 Form 10-K, File No. 1-8222)

10.22.1 Copy of Capital Funds Agreement between the Company and Connecticut Yankee dated as of September 1, 1964. (Exhibit C-67, 1981 Form 10-K, File No. 1-8222)

10.23 Copy of Five-Year Capital Contribution Agreement between the Company and Connecticut Yankee dated as of November 1, 1980. (Exhibit C-68, 1981 Form 10-K, File No. 1-8222)

10.24 Form of Guarantee Agreement dated as of November 7, 1981, among certain banks, Connecticut Yankee and the Company, relating to revolving credit notes of Connecticut Yankee. (Exhibit C-69, 1981 Form 10-K, File No. 1-8222)

10.25 Form of Guarantee Agreement dated as of November 13, 1981, between The Connecticut Bank and Trust Company, as Trustee, and the Company, relating to debentures of Connecticut Yankee. (Exhibit C-70, 1981 Form 10-K, File No. 1-8222)

10.26 Preliminary Vermont Support Agreement re Quebec interconnection between VELCO and among seventeen Vermont Utilities dated May 1, 1981. (Exhibit C-97, 1982 Form 10-K, File No. 1-8222)

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

10.27 Vermont Participation Agreement for Quebec Interconnection between VELCO and among seventeen Vermont Utilities dated July 15, 1982. (Exhibit C-99, 1982 Form 10-K, File No. 1-8222)

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

10.28 Vermont Electric Transmission Company Capital Funds Support Agreement between VELCO and among sixteen Vermont Utilities dated July 15, 1982. (Exhibit C-100, 1982 Form 10-K, File No. 1-8222)

10.29 Vermont Transmission Line Support Agreement, Vermont Electric Transmission Company and twenty New England Utilities dated December 1, 1981, as amended by Amendment No. 1 dated June 1, 1982, and by Amendment No. 2 dated November 1, 1982. (Exhibit C-101, 1982 Form 10-K, File No. 1-8222)

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

10.30 Phase 1 Terminal Facility Support Agreement between New England Electric Transmission Corporation and twenty New England Utilities dated December 1, 1981, as amended by Amendment No. 1 dated as of June 1, 1982 and by Amendment No. 2 dated as of November 1, 1982. (Exhibit C-102, 1982 Form 10-K, File No. 1-8222)

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

10.32 Agreement for Joint Ownership, Construction and Operation of the Joseph C. McNeil Generating Station by and between City of Burlington Electric Department, Central Vermont Realty, Inc. and Vermont Public Power Supply Authority dated May 14, 1982. (Exhibit C-107, 1983 Form 10-K, File No. 1-8222)

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

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

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

10.33 Transmission Service Contract between Central Vermont Public Service Corporation and The Vermont Electric Generation & Transmission Cooperative, Inc. dated May 14, 1984. (Exhibit C-111, 1984 Form 10-K, File No. 1-8222)

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

10.35 Copy of Allocation Contract for Hydro-Québec 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-Québec 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-Québec 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-Québec 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-Québec 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-Québec 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-Québec Participation Agreement dated April 1, 1988 for 600 MW between Hydro-Québec and Vermont Joint Owners of Highgate. (Exhibit 10-177, 1988 Form 10-K, File No. 1-8222)

10.52.1 Hydro-Québec 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-Québec 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-Québec and Vermont Utilities dated December 29, 1988. (Exhibit 10-183, 1988 Form 10-K, File No. 1-8222)

10.54 Settlement Agreement effective dated June 1, 2001 to which the Company is a party re: Vermont Yankee Nuclear Power Corporation. (Exhibit 10-84, Form 10-Q, June 30, 2001, File No. 1-8222)

10.55 Form of Secondary Purchaser Settlement Agreement dated December 6, 2001, with Acknowledgement and Consent of VELCO, among the Company, Green Mountain Power Corporation and each of: City of Burlington Electric Department; Village of Lyndonville Electric Department; Village of Northfield Electric Department; Village of Orleans Electric Department; Town of Hardwick Electric Department; Town of Stowe Electric Department; and, Washington Electric Cooperative. (Exhibit 10-85, 2001 Form 10-K, File No. 1-8222)

10.56 Memorandum of Understanding, dated September 11, 2006, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.93, Current Report on Form 8-K Filed September 11, 2006, File No. 1-8222)

10.56.1 First Amendment to Memorandum of Understanding, dated November 3, 2006, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.93, Current Report on Form 8-K Filed November 6, 2006, File No. 1-8222)

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

10.58 Amended and Restated 1991 Transmission Agreement between Vermont Transco, LLC and (to electric utilities furnishing service within the State of Vermont) effective June 20, 2006. (Exhibit 10.95, 2006 Form 10-K, File No. 1-8222)

10.59 Memorandum of Understanding, dated November 29, 2007, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.96, Current Report on Form 8-K Filed November 30, 2007, File No. 1-8222)

10.60 Credit Agreement dated as of December 28, 2007 between Central Vermont Public Service Corporation, as Borrower and KeyBank National Association, as Lender. (Exhibit 10.97, Current Report of Form 8-K Filed January 4, 2008, File No. 1-8222)

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

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

10.63 Agreement between Central Vermont Public Service Corporation and Local Union No. 300 International Brotherhood of Electrical Workers Effective as of January 1, 2009. (Exhibit 10.100, Current Report on Form 8-K Filed January 7, 2009, File No. 1-8222)

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

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

10-66 Memorandum of Understanding, dated December 20, 2010, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10-65, Current Report on Form 8-K filed December 22, 2010, File No. 1-8222)

10.67 Credit Agreement dated as of October 25, 2011 between Central Vermont Public Service Corporation, as Borrower and KeyBank National Association, as Lender. (Exhibit 10.67, Current Report on Form 8-K Filed October 26, 2011, File No. 1-8222)

EXECUTIVE COMPENSATION PLANS AND ARRANGEMENTS

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

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

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

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

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

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

A 10.5	Form of Change In Control Agreement to Become Effective April 2009. (Exhibit A 10.5.2, Form 10-Q, March 31, 2008, File No. 1-8222)
A 10.6	Form of Change in Control Agreement effective March 1, 2011. (Exhibit A 10.6, 2010 Form 10-K, File No. 1-8222)
A 10.7	2000 Stock Option Plan for Key Employees. (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 28, 2000, File No. 1-8222) - (Exhibit A 10.95, September 30, 2006 Form 10-Q, File No. 1-8222)
A 10.8	Deferred Compensation Plan for Officers and Directors of Central Vermont Public Service Corporation, Amended and Restated Effective August 4, 2008, With An Effective Date of January 1, 2005. (Exhibit A 10.7.1, Form 10-Q, June 30, 2008, File No. 1-8222)
A 10.9	Omnibus Stock Plan (Amended and Restated 2002 Long-Term Incentive Plan). (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 28, 2008, File No. 1-8222)
A 10.10	Performance Share Incentive Plan, Effective January 1, 2010. (Exhibit A 10.17, Current Report on Form 8-K Filed March 5, 2010, File No. 1-8222)
A 10.11	Performance Share Incentive Plan, Effective January 1, 2011. (Exhibit A 10.12, 2010 Form 10-K, File No. 1-8222)
A 10.12	Performance Share Incentive Plan, Effective January 1, 2012. (Exhibit A 10.22, Current Report on Form 8-K Filed March 2, 2012, File No. 1-8222)
A 10.13	Form of Central Vermont Public Service Performance Share Agreement Pursuant to the Performance Share Incentive Plan. (Exhibit A 10.101, Form 10-Q, September 30, 2004, File No. 1-8222)
A 10.14	Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2002 Long-Term Incentive Plan. (Exhibit A 10.102, Form 10-Q, September 30, 2004, File No. 1-8222)
A 10.15	Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2000 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.103, Form 10-Q, September 30, 2004, File No. 1-8222)
A 10.16	Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 1997 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.104, Form 10-Q, September 30, 2004, File No. 1-8222)
A 10.17	Form of Indemnity Agreement between Directors and Executive Officers and Central Vermont Public Service Corporation. (Exhibit A 10.105, 2004 Form 10-K, File No. 1-8222)
A 10.18	Consulting Services Agreement between Robert H. Young and Central Vermont Public Service Corporation dated effective June 1, 2011. (Exhibit No. A 10.19, Current Report on Form 8-K Filed April 22, 2011, File No. 1-8222)
A 10.19	Form of First Amendment to the Change In Control Agreement, Effective April 6, 2009 between Central Vermont Public Service Corporation and ___________ ("Executive"). (Exhibit No. A 10.20, Current Report on Form 8-K Filed January 11, 2012, File No. 1-8222)
A 10.20	Management Incentive Plan, Effective January 1, 2012. (Exhibit A 10.21, Current Report on Form 8-K Filed March 2, 2012, 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 (CVPS - D&T)

* 23.2 Consent of Independent Registered Public Accounting Firm (D&T - VELCO)

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

* 23.4 Consent of Independent Registered Public Accounting Firm (D&T - VT Transco)

* 23.5 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.

101.INS XBRL Instance Document

101.SCH XBRL Schema Document

101.CAL XBRL Calculation Linkbase Document

101.DEF XBRL Definition Linkbase Document

101.LAB XBRL Label Linkbase Document

101.PRE XBRL Presentation Linkbase Document

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

March 14 , 2012

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 14 , 2012.

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

By: 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)

	2011	2010	2009	2008	2007
Earnings, as defined by S-K 503(d):					
Pre-tax income from continuing operations	$ 9,515	$ 35,616	$ 31,423	$ 27,125	$ 22,553
Plus: distributed income	19,385	14,235	10,695	10,694	4,894
Less: equity in earnings	(27,733)	(21,098)	(17,472)	(16,264)	(6,430)
Less: interest capitalized	(60)	(75)	(65)	(105)	(150)
Less: preference security dividends, as defined	(614)	(626)	(558)	(613)	(525)
Plus: fixed charges, as below	14,968	12,949	12,870	13,331	10,371
Total Earnings, as defined	$ 15,461	$ 41,001	$ 36,893	$ 34,168	$ 30,713
Fixed charges, as defined:					
Interest on debt	$ 13,774	$ 11,621	$ 11,715	$ 11,648	$ 8,490
Interest on uncertain tax positions	10	0	(127)	39	51
Imputed interest in rental charges	570	702	724	1,031	1,305
Preferred dividends, as defined	614	626	558	613	525
Total fixed charges, as defined	$ 14,968	$ 12,949	$ 12,870	$ 13,331	$ 10,371
Ratio of Earnings to Fixed Charges	**1.03**	**3.17**	**2.87**	**2.56**	**2.96**

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
Catamount Resources 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) Catamount Resources Corporation has one wholly owned subsidiary operating in the United States.

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 14, 2012, relating to the consolidated financial statements of Central Vermont Public Service Corporation ("the Company"), which report expresses an unqualified opinion and refers to the reports of other auditors 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, 2011.

Deloitte & Touche LLP

Boston, Massachusetts
March 14, 2012

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 Registration Statement Nos. 333-141681, 333-151019 and 333-162979 on Form S-3 and Registration Statement No. 333-152872 on Form S-8 of Central Vermont Public Service Corporation of our report dated March 13, 2012, relating to the consolidated balance sheet of Vermont Electric Power Company, Inc. and subsidiaries as of December 31, 2011, and the related consolidated statement of income, stockholders' equity, and cash flow for the year ended December 31, 2011, appearing in the Annual Report on Form 10-K of Central Vermont Public Service Corporation for the year ended December 31, 2011.

Deloitte & Touche LLP

BOSTON, MA
March 13, 2012

Independent Auditor's Report

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, 2011, with respect to the consolidated balance sheet of Vermont Electric Power Company, Inc. and subsidiary as of December 31, 2010, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2010, which report appears in the December 31, 2011 annual report on Form 10-K of Central Vermont Public Service Corporation.

KPMG LLP

Burlington, Vermont
March 13, 2012

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Vermont Electric Power Company, Inc. as Manager of Vermont Transco LLC

We consent to the incorporation by reference in Registration Statement (Nos. 333-141681, 333-151019 and 333-162979) on Form S-3 and Registration Statement (No. 333-152872) on Form S-8 of Central Vermont Public Service Corporation of our report dated March 13, 2012, relating to the balance sheet of Vermont Transco LLC as of December 31, 2011, and the related statements of income, changes in members' equity, and cash flow for the year ended December 31, 2011, appearing in the Annual Report on Form 10-K of Central Vermont Public Service Corporation for the year ended December 31, 2011.

Deloitte & Touche LLP

BOSTON, MA
March 13, 2012

Independent Auditor's Report

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, 2011, with respect to the balance sheet of Vermont Transco LLC as of December 31, 2010, and the related statements of income, changes in members' equity, and cash flows for each of the years in the two-year period ended December 31, 2010, which report appears in the December 31, 2011 annual report on Form 10-K of Central Vermont Public Service Corporation.

KPMG LLP

Burlington, Vermont
March 13, 2012

EXHIBIT 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned Chief Executive Officer and Senior 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, 2011, under the Securities Exchange Act of 1934, as amended, does each for himself/herself and not for one another, hereby constitute and appoint Lawrence J. Reilly 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 27th day of February, 2012.

Lawrence J. Reilly
President and Chief Executive Officer and Director
(Principal Executive Officer)

Pamela J. Keefe
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Robert L. Barnett, Director

Robert G. Clarke, Director

John M. Goodrich, Director

Robert B. Johnston, Director

Elisabeth B. Robert, Director

William R. Sayre, Director

Janice L. Scites, Director

William J. Stenger, Director

Douglas J. Wacek, Director

EXHIBIT 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned Chief Executive Officer and Senior 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, 2011, under the Securities Exchange Act of 1934, as amended, does each for himself/herself and not for one another, hereby constitute and appoint Lawrence J. Reilly 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 7th day of March, 2012.

____
Lawrence J. Reilly
President and Chief Executive Officer and Director
(Principal Executive Officer)

____
Pamela J. Keefe
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

____
Robert L. Barnett, Director

____
Robert G. Clarke, Director

____
John M. Goodrich, Director

____
Robert B. Johnston, Director

____
Elisabeth B. Robert, Director

____
William R. Sayre, Director

____
Janice L. Scites, Director

____
William J. Stenger, Director

____
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, Lawrence J. Reilly, 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 fourth 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 14 , 2012

Lawrence J. Reilly
Chief Executive Officer
(Principal 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 fourth 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 14, 2012

Pamela J. Keefe

Pamela J. Keefe
Chief Financial Officer
(Principal Financial and Accounting 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, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I Lawrence J. Reilly, 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.

Lawrence J. Reilly
Chief Executive Officer
(Principal Executive Officer)
March 14, 2012

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, 2011 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.

Pamela J. Keefe
Pamela J. Keefe
Chief Financial Officer
(Principal Financial and Accounting Officer)
March 14 , 2012

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 Subsidiaries

Consolidated Financial Statements as of December 31, 2011 and 2010, and for Each of the Years in the Three-Year Period Ended December 31, 2011, and Report of Independent Registered Public Accounting Firm

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES

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Deloitte.

Deloitte & Touche LLP
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USA

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www.deloitte.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Vermont Electric Power Company, Inc.
Rutland, Vermont

We have audited the accompanying consolidated balance sheet of Vermont Electric Power Company, Inc. and subsidiaries (the "Company") as of December 31, 2011, and the related consolidated statements of income, stockholders' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The consolidated financial statements of the Company for the years ended December 31, 2010 and 2009 were audited by other auditors whose report, dated March 8, 2011, expressed an unqualified opinion on those statements.

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 the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included 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 audit provides a reasonable basis for our opinion.

In our opinion, such 2011 consolidated financial statements present fairly, in all material respects, the financial position of Vermont Electric Power Company, Inc. and subsidiaries as of December 31, 2011, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

March 13, 2012

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2011 AND 2010

ASSETS	2011	2010
UTILITY PLANT	$ 961,315,767	$ 842,418,126
LESS ACCUMULATED DEPRECIATION AND AMORTIZATION	(172,564,754)	(107,874,057)
Net utility plant	788,751,013	734,544,069
NONUTILITY PROPERTY	2,411,563	
INVESTMENT IN VERMONT ELECTRIC TRANSMISSION COMPANY, INC.		560,108
CURRENT ASSETS:		
Cash	10,147,908	2,134,070
Restricted cash	1,241,195	
Bond sinking fund deposits	12,571,333	564,000
Bond interest deposits	2,922,933	4,537,947
Accounts receivable:		
Affiliated companies	19,718,393	12,219,169
Other	12,283,019	9,929,570
Note receivable — related party		125,000
Materials and supplies	7,918,387	7,333,500
Income tax receivable	202,962	336,145
Prepaids and other assets	1,976,816	1,459,759
Total current assets	68,982,946	38,639,160
REGULATORY AND OTHER ASSETS:		
Regulatory assets	15,096,893	9,167,401
Unamortized debt expense — net	2,417,295	2,563,063
Cash surrender value of life insurance policies	3,986,446	3,770,968
Deferred project costs and other	4,514,651	5,740,634
Total regulatory and other assets	26,015,285	21,242,066
TOTAL ASSETS	$ 886,160,807	$ 794,985,403

See notes to consolidated financial statements.

CAPITALIZATION AND LIABILITIES	2011	2010
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	1,403,245	1,663,772
	25,391,045	25,651,572
Class C preferred stock, $100 par value per share; authorized 125,000 shares; 97,068 shares issued and outstanding	145,602	145,602
Total stockholders' equity attributable to VELCO	25,536,647	25,797,174
Equity interest of noncontrolling members in Vermont Transco LLC	391,932,767	375,944,428
Total stockholders' equity	417,469,414	401,741,602
First mortgage bonds — net of current maturities	297,483,000	317,272,000
Total capitalization	714,952,414	719,013,602
COMMITMENTS AND CONTINGENCIES		
CURRENT LIABILITIES:		
Current maturities of long-term obligations	19,789,000	11,821,000
Line of credit	62,701,113	44,917
Bank overdraft	1,433,309	891,788
Accounts payable:		
Affiliated companies	1,872,610	701,357
Other	26,429,333	20,148,197
Accrued interest	4,527,081	4,534,585
Accrued taxes	689,877	562,321
Accrued construction expenses	7,022,409	4,699,609
Accrued expenses	2,655,894	3,970,593
Total current liabilities	127,120,626	47,374,367
RESERVES AND DEFERRED CREDITS:		
Regulatory liabilities	10,976,355	4,666,950
Deferred tax liability	14,332,718	12,498,349
Deferred compensation	4,968,736	4,836,176
Deferred income and other	2,432,745	778,184
Accrued pension and postretirement liabilities	11,377,213	5,817,775
Total non-current liabilities	44,087,767	28,597,434
TOTAL CAPITALIZATION AND LIABILITIES	$ 886,160,807	$ 794,985,403

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR EACH OF THE YEARS IN THE THREE-YEAR PERIOD ENDED DECEMBER 31, 2011

	2011	2010	2009
OPERATING REVENUES:			
Transmission revenues	$ 134,595,208	$ 102,547,684	$ 90,649,734
Sales of power	497,871	468,517	510,823
Rent of transmission facilities to others	998,987	999,587	2,435,380
Total operating revenues	136,092,066	104,015,788	93,595,937
OPERATING EXPENSES:			
Transmission expenses:			
Operations	4,743,376	5,408,961	3,369,434
Maintenance	7,236,221	6,490,760	5,625,653
Rents	50,860	44,183	41,705
Purchased power	497,871	468,517	510,823
Administrative and general expenses	7,615,836	5,581,386	7,718,153
Depreciation and amortization	20,915,092	16,031,969	13,942,091
Taxes other than income	15,764,015	11,445,565	10,485,062
Total operating expenses	56,823,271	45,471,341	41,692,921
OPERATING INCOME	79,268,795	58,544,447	51,903,016
OTHER (INCOME) EXPENSE:			
Interest on first mortgage bonds	17,921,196	18,197,213	13,477,726
Other interest expense	892,585	1,356,486	1,495,343
Amortization of debt expense	145,769	148,791	101,560
Allowance for borrowed funds used during construction	(1,000,138)	(4,394,038)	(2,151,956)
Allowance for equity funds used during construction	(1,518,157)	(6,566,209)	(2,977,719)
Government grants and other	758,702	(1,918)	12,708
Interest, government grants and other income	(669,280)	(151,290)	(239,474)
Equity in earnings of affiliated company		(73,677)	(29,457)
Net other (income) expense	16,530,677	8,515,358	9,688,731
INCOME BEFORE NONCONTROLLING INTEREST AND INCOME TAX	62,738,118	50,029,089	42,214,285
INCOME TAX	2,080,919	1,055,646	2,337,632
NET INCOME	60,657,199	48,973,443	39,876,653
NONCONTROLLING INTEREST IN THE INCOME OF VERMONT TRANSCO LLC	58,143,598	45,728,401	36,201,872
NET INCOME ATTRIBUTABLE TO VELCO	$ 2,513,601	$ 3,245,042	$ 3,674,781

See notes to consolidated financial statements.

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR EACH OF THE YEARS IN THE THREE-YEAR PERIOD ENDED DECEMBER 31, 2011

	Common Stock		Preferred Stock	Retained Earnings	Total Stockholder's Equity
	Class B	Class C			
BALANCE — 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)
BALANCE — December 31, 2009	21,997,700	1,990,100	145,602	1,192,858	25,326,260
Net income attributable to VELCO				3,245,042	3,245,042
Dividends declared and paid				(2,774,128)	(2,774,128)
BALANCE — December 31, 2010	21,997,700	1,990,100	145,602	1,663,772	25,797,174
Net income attributable to VELCO				2,513,601	2,513,601
Dividends declared and paid				(2,774,128)	(2,774,128)
BALANCE — December 31, 2011	$21,997,700	$1,990,100	$145,602	$ 1,403,245	$25,536,647

See notes to consolidated financial statements.

VERMONT ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR EACH OF THE YEARS IN THE THREE-YEAR PERIOD ENDED DECEMBER 31, 2011

	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 60,657,199	$ 48,973,443	$ 39,876,653
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	20,343,742	15,460,619	13,370,741
Amortization of regulatory assets	571,350	571,350	571,350
Amortization of debt expense	145,769.	148,791	101,560
Deferred income tax expense	1,956,416	1,073,208	1,318,778
Other	619,074		
Equity in earnings of affiliated company		(73,677)	(29,457)
Dividends from subsidiary		15,728	15,844
Changes in assets and liabilities:			
Accounts receivable	(9,852,673)	(154,893)	(1,060,879)
Materials and supplies	(584,887)	(1,084,504)	435,812
Income tax receivable	133,183	(166,150)	480,946
Accounts payable	3,649,165	(4,383,557)	3,305,420
Employee benefit plan funding	716	(220,676)	680,635
Deferred compensation	132,560	(933,436)	325,757
Other assets and liabilities	1,885,158	(3,776,440)	830,768
Net cash provided by operating activities	79,656,772	55,449,806	60,223,928
CASH FLOWS FROM INVESTING ACTIVITIES:			
Change in bond sinking fund deposits	(12,007,333)	(38,000)	(36,000)
Repayments to (advances from) related party	125,000	800,000	(225,000)
Capital expenditures — net	(64,635,962)	(121,510,078)	(166,135,303)
Change in cash surrender value of life insurance policies	(215,478)	(283,482)	(486,334)
Net cash used in investing activities	(76,733,773)	(121,031,560)	(166,882,637)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Change in bank overdraft	541,521	(2,083,243)	1,380,293
Proceeds from bond issuance			135,000,000
Repayment of bonds	(11,821,000)	(2,161,000)	(2,014,000)
Debt issue costs		311	(1,014,724)
Proceeds from (repayments of) line of credit	62,656,196	44,917	(20,857,520)
Repayment of other long-term debt		(152,115)	(292,121)
Issuance of VT Transco membership units	1,150,000	67,962,280	60,047,790
Distribution of VT Transco earnings to noncontrolling members	(43,305,259)	(33,147,677)	(23,257,250)
Cash dividends on common stock	(2,758,597)	(2,758,597)	(2,758,597)
Cash dividends on preferred stock	(15,531)	(15,531)	(15,532)
Net cash provided by financing activities	6,447,330	27,689,345	146,218,339
NET INCREASE (DECREASE) IN CASH	9,370,329	(37,892,409)	39,559,630
CASH — Beginning of year	777,579	40,026,479	466,849
CASH — End of year	$ 10,147,908	$ 2,134,070	$ 40,026,479
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid during the year for interest — net of amounts capitalized	$ 16,408,365	$ 8,528,978	$ 7,830,970
Cash paid for income taxes	$ -	$ 570,250	$ (49,138)

NONCASH ACTIVITY — In 2011, 2010, and 2009, the Company recorded accounts payable related to capital expenditures and accrued construction expenses of $6,018,659, $7,725,685, and ($337,977), respectively.

See notes to consolidated financial statements.

1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

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), VELCO and Vermont Electric Transmission Company, Inc. (VETCO). 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 affiliate, VETCO (unconsolidated prior to 2011) (see Note 10), 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 32% of its Class C common stock and 49% 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.

Consolidation — The accompanying consolidated financial statements include the accounts of VELCO, VT Transco and VETCO (effective 2011) as VELCO is the primary beneficiary and controls the financial and operating policies of VT Transco and VETCO. Ownership interests of members other than the Company in the equity of VT Transco are 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. Intercompany balances and transactions have been eliminated in consolidation.

In 2011, the Company considered the ability of the Board of Directors of VELCO to influence the day to day management of the activities which most significantly impact VETCO, and their ownership of VETCO, and determined VELCO was the primary beneficiary of VETCO, and consolidated the balance sheet and results of VETCO for the year ended December 31, 2011. Management determined the impact on the prior years was immaterial.

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 $1,701,555 and $2,126,944 as of December 31, 2011 and 2010, 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 $1,386,630 and $1,532,591 as of December 31, 2011 and 2010, respectively.

As more fully described in Note 9, 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 $10,949,323 and $5,390,601 at December 31, 2011 and 2010, respectively.

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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents — The Company considers all liquid investments with an original maturity of three months or less when acquired to be cash and cash equivalents. Cash and cash equivalents consists primarily of cash in banks.

Restricted Cash — The Company has restricted cash related to a settlement agreement and a vendor contract, and consists of cash in banks.

Bond Sinking Fund and Interest Deposits — The terms of our bond agreements require that interest and principal be deposited monthly into these deposit accounts. The interest and principal is paid on a quarterly basis. These deposits consist of cash and cash equivalents in banks.

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. The 1991 Vermont Transmission Agreement 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 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 $402,010 at December 31, 2011 and 2010, respectively, and is reported in prepaids and other assets in the accompanying consolidated financial statements.

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, 2011, 2010 and 2009, 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.

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 or asset group be tested for possible impairment, the Company first compares undiscounted cash flows expected to be generated by that asset or asset group to the carrying value. 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.

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 increased revenue collected as a result of depreciation of the property. The Company capitalized AFUDC at an average rate of 6.37%, 7.5%, and 5.75% in 2011, 2010, and 2009, respectively.

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

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 $145,768, $148,791, and $101,560 in 2011, 2010, and 2009, respectively.

Derivative Financial Instruments — The Company entered into a forward starting interest rate swap to mitigate the risk of changes in interest rates on $10 million of the line of credit balance. The Company does not apply hedge accounting to this swap.

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 and VETCO 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.

The Company provides reserves for potential payments of tax to various tax authorities related to uncertain tax positions. Reserves are based on a determination of whether and how much of a tax benefit taken by the Company in its tax filings or positions is more likely than not to be realized following resolution of the uncertainty. Potential interest and penalties associated with such uncertain tax positions is recorded as a component of interest expense and administrative and general expense, respectively. Through December 31, 2011, the Company has not identified any material uncertain tax positions.

Pension and Other Postretirement Plans — The Company 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 final average pay.

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.

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 valuation 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.

Fair Value Measurements — The fair values of cash, accounts receivable, accounts payable, accrued expenses, and note payable approximate the carrying amounts due to their short-term nature. See note 13 for further discussion.

Concentrations of Credit Risk — Financial instruments that subject the Company to significant concentrations of credit risk consist primarily of cash, bond sinking fund deposits, and an interest rate swap. Substantially, all of the Company's cash is held at one financial institution that management believes to be of high-credit quality.

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.

Government Grants — The Company recognizes government grants when there is reasonable assurance that the Company will comply with the conditions attached to the grant arrangement and the grant will be received. Government grants are recognized in the income statement over the periods in which we recognize the related costs for which the government grant is intended to compensate.

When government grants are related to the oversight of sub-recipients, the grants are recognized as other income in the consolidated income statement. For government grants related to reimbursements of capital expenditures, the grants are recognized as a reduction of the basis of the asset and recognized in the income statement over the estimated useful life of the depreciable asset as reduced depreciation expense. For government grants related to billings from sub-recipients, the grants are recognized as receivables from the government agency and payables to the sub-recipient on the balance sheet as we do not have rights to the funds passing through to sub-recipients. The Company recorded approximately $70,000 in government grants receivable on the consolidated balance sheet in prepaids and other assets at December 31, 2011.

3. UTILITY PLANT

Utility plant consists of the following at December 31, 2011 and 2010:

	2011	2010
Land and rights of way	$ 51,621,141	$ 80,148,733
Transmission equipment	741,335,075	657,841,309
Communications equipment	37,945,686	22,542,074
Buildings and office equipment	72,874,426	59,813,941
Construction work-in-process	57,539,439	22,072,069
	961,315,767	842,418,126
Less accumulated depreciation and amortization	172,564,754	107,874,057
	$788,751,013	$734,544,069

Depreciation and amortization expense was $20,343,742, $15,460,619, and $13,370,741 for the years ended December 31, 2011, 2010, and 2009, respectively.

4. LONG TERM DEBT

First Mortgage Bonds — The Company's First Mortgage Bonds outstanding include the following series at December 31, 2011 and 2010:

	2011	2010
Series L, 7.30% due through 2018	$ 6,054,000	$ 6,758,000
Series N, 7.42%, due through 2012	18,557,000	19,727,000
Series O, 6.26% due through 2034	22,161,000	22,608,000
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	125,500,000	135,000,000
	317,272,000	329,093,000
Less bonds to be retired within one year	19,789,000	11,821,000
	$297,483,000	$317,272,000

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:

Years Ending December 31	
2012	$ 19,789,000
2013	11,821,000
2014	13,916,000
2015	14,513,000
2016	15,621,000
Thereafter	241,612,000
	$317,272,000

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 $105,757,333, at December 31, 2011.

5. LINE OF CREDIT

The Company has an unsecured $100,000,000 line of credit agreement with a financial institution, reduced by certain standby letters of credit totaling $325,000, expiring on April 30, 2012, to provide interim financing for utility plant construction. This line is renewed each year for a one year term. The Company plans to refinance the line of credit when it comes due on April 30, 2012. If the Company is unable to obtain the line of credit, it has the ability to issue an equity call to its members. As part of this agreement, the Company agrees to pay 0.10% per annum on the daily unused line of credit amount. The interest rate at December 31, 2011 is at the Company's option of either LIBOR plus .75% for 30, 60 or 90 days or overnight LIBOR plus 1.00%. Average daily borrowings were $19,610,628 in 2011 and $23,926,753 in 2010 at a weighted average interest rate of 1.73% and 2.72%, respectively. The outstanding balance at December 31, 2011 and 2010, amounted to $62,017,113 and $44,917, respectively. Interest recorded for these borrowings in 2011, 2010 and 2009 was $340,311, $650,707 and $832,623, respectively.

6. INCOME TAXES

Federal and state income tax expenses (benefits) for the years ended December 31, 2011, 2010, and 2009, are as follows:

	2011	2010	2009
Federal:			
Current	$ 118,259	$ 75,871	$ 744,661
Deferred	1,518,324	809,550	1,098,365
Total federal	1,636,583	885,421	1,843,026
State:			
Current	6,244	(99,878)	274,193
Deferred	438,092	270,103	220,413
Total state	444,336	170,225	494,606
Total federal and state income tax	$2,080,919	$1,055,646	$2,337,632

The difference between the actual tax rate and the statutory tax rate for 2011, 2010, and 2009 (computed by applying the U.S. statutory corporate tax rate to earnings before taxes), is primarily attributable to the earnings of Transco which are taxed as a partnership.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010, are presented below:

	2011	2010
Deferred tax assets:		
Deferred compensation	$ 620,684	$ 453,642
Other	2,693,266	2,199,448
Total gross deferred tax assets	3,313,950	2,653,090
Valuation allowance	(1,087,199)	
Deferred tax liability — utility plant depreciation	(16,559,469)	(15,151,439)
Net deferred tax liability	$(14,332,718)	$(12,498,349)

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 valuation allowance for deferred tax assets as of January 1, 2011 and 2010 was $1,087,199, related to VETCO fixed assets. The Company has recorded a valuation allowance related to the book amortization of land (which is recovered in rates) after concluding that the land would not likely be amortized or otherwise recovered for tax purposes. In addition, the Company has recorded a valuation allowance related to the excess of the book amortization of rights of way compared to tax amortization after concluding that it would not likely be amortized or otherwise recovered for tax purposes for the foreseeable future. The ultimate realization of the remaining deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax assets, projected future taxable income, and tax planning strategies in making this assessment. Based upon these factors, management believes it is more likely than not that the Company will not realize the benefits of these deductible differences.

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 return basis, in accordance with a tax sharing agreement. In 2009 the Company utilized all of its $641,776 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.

Currently, 2008-2011 are subject to potential examination by tax authorities, principally Federal and the State of Vermont. No examinations have commenced at December 31, 2011.

7. 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. $15,531 was paid in Class C preferred dividends for the years ended December, 31, 2011, 2010 and 2009, respectively.

8. NONCONTROLLING MEMBERS' EQUITY OF VT TRANSCO

The Company follows FASB ASC Subtopic 810-10, *Consolidation — Overall*, which requires certain 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.

VT Transco's noncontrolling members own 90.8% of VT Transco, and 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		
	2011	2010	2009
Beginning balance	$375,944,428	$295,401,424	$222,409,012
Issuance of membership units	1,150,000	67,962,280	60,047,790
Income of VT Transco	58,143,598	45,728,401	36,201,872
Distributions of VT Transco income	(43,305,259)	(33,147,677)	(23,257,250)
Ending balance	$391,932,767	$375,944,428	$295,401,424

VT Transco is taxed as a partnership, and therefore income taxes are the responsibility of VT Transco's members (except certain tax-exempt members), and are not reflected in the balances above. 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.

A reconciliation of total equity for VELCO for the year ended December 31, 2011 is as follows:

	For the Year Ended December 31, 2011		
	Equity Attributable to VELCO	Equity Attributable to Non-controlling Interests	Total Equity
Beginning balance	$25,797,174	$375,944,428	$401,741,602
Income of VT Transco	2,513,601	58,143,598	60,657,199
Issuance of membership units		1,150,000	1,150,000
Dividends and distributions	(2,774,128)	(43,305,259)	(46,079,387)
Ending balance	$25,536,647	$391,932,767	$417,469,414

9. PENSION AND OTHER POSTRETIREMENT BENEFITS

The Company reports 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, 2011 and 2010, the Company recorded a regulatory asset of $10,041,650 and $4,546,992, respectively, an unfunded defined benefit pension obligation of $10,428,404 and $4,934,040, respectively, a postretirement healthcare obligation of $948,809 and $883,735, respectively, and related regulatory asset of $907,673 and $843,609, respectively.

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 "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, 2011 and 2010:

	Pension Benefits	
	2011	**2010**
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 20,023,874	$17,171,882
Service cost	1,039,809	1,013,619
Interest cost	1,088,484	1,008,694
Actuarial loss	5,033,150	1,363,118
Benefits paid	(505,554)	(533,439)
Benefit obligation at end of year	26,679,763	20,023,874
Change in plan assets:		
Fair value of plan assets at beginning of year	15,089,834	12,875,783
Actual return on plan assets	542,078	1,722,490
Employer contribution	1,125,000	1,025,000
Benefits paid	(505,554)	(533,439)
Fair value of plan assets at end of year	16,251,358	15,089,834
Funded status	$(10,428,405)	$ (4,934,040)
Accumulated benefit obligation	$ 19,264,336	$14,680,249

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2011 and 2010, which are recorded as a regulatory asset, are as follows:

	2011	**2010**
Net actuarial loss	$ 9,759,843	$4,217,808
Unrecognized prior service cost	281,808	329,184
	$10,041,651	$4,546,992

The amount of the regulatory asset expected to be recognized as a component of net periodic pension cost in 2012 is $164,734.

Net periodic benefit cost for the years ended December 31, 2011, 2010, and 2009, are as follows:

	Pension Benefits		
	2011	2010	2009
Components of net periodic benefit cost:			
Service cost	$ 1,039,809	$ 1,013,619	$ 1,016,923
Interest cost	1,088,484	1,008,694	944,414
Expected return on plan assets	(1,168,321)	(1,078,827)	(1,026,169)
Recognized net actuarial loss	117,357	28,974	11,235
Net amortization	47,377	52,476	52,476
Net periodic benefit cost	$ 1,124,706	$ 1,024,936	$ 998,879

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

	Pension Benefits		
	2011	2010	2009
Weighted average assumptions:			
Discount rate, pension expense	5.56 %	6.00 %	6.00 %
Discount rate, projected benefit obligation	4.40	5.56	6.00
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 2012 to 2016 and the aggregate benefits expected to be paid in the five years from 2017 to 2021 are as follows:

	Pension Benefit Payments
Fiscal years ending December 31:	
2012	$ 429,613
2013	482,816
2014	556,674
2015	550,672
2016	558,620
2017–2021	4,387,626
Expected contribution for next fiscal year	1,125,000

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, 2011 and 2010:

	Fair Value		Target	
Asset Class	2011	2010	2011	2010
Money market	$ 2,480,407	$ 1,348,099	15 %	9 %
Equities	8,283,812	9,306,708	51	62
Fixed income	5,487,139	4,435,017	34	29
Total	$16,251,358	$15,089,824	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. Plan investments held at December 31, 2011, are classified as Level 1 based on the fair value hierarchy discussed in Note 13.

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, 2011, 2010, and 2009, the Company contributed $150,213, $131,129 and $32,141, respectively, toward these benefits. The Company anticipates contributing $180,000 for these benefits in 2012.

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 following table sets for the plan's benefit obligations, fair value of plan assets and funded status at December 31, 2011 and 2010:

	2011	**2010**
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 1,635,382	$ 1,496,132
Service cost	111,908	107,413
Interest cost	80,173	81,284
Actuarial gain	88,310	128,721
Benefits paid	(50,950)	(178,168)
Benefit obligation at end of year	1,864,823	1,635,382
Change in plan assets:		
Fair value of plan assets at beginning of year	751,647	573,400
Actual return on plan assets	14,154	47,118
Employer contribution — net of VEBA reimbursement	201,163	309,297
Benefits paid	(50,950)	(178,168)
Fair value of plan assets at end of year	916,014	751,647
Funded status	$ (948,809)	$ (883,735)

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2011 and 2010, which are recorded as a regulatory asset, are as follows:

	2011	2010
Change in measurement date to be recovered in rates	$ 16,676	$ 38,911
Net actuarial loss	890,997	804,698
	$907,673	$843,609

The amount of the regulatory asset expected to be recognized as a component of net periodic benefit cost in 2012 is $63,824.

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 $9,772 and a 1.0% decrease in the trend rate would decrease the postretirement accumulated benefit obligation by $9,210 in 2012.

Net periodic benefit costs as of December 31, 2011, 2010, and 2009, are as follows:

	Postretirement Benefits		
	2011	2010	2009
Components of net periodic benefit cost:			
Service cost	$111,908	$107,413	$ 93,871
Interest cost	80,173	81,284	82,303
Expected return on plan assets	(53,732)	(42,747)	(40,515)
Recognized net actuarial loss	22,234	22,234	22,234
Net amortization	41,590	37,768	32,953
Net periodic benefit cost	$202,173	$205,952	$190,846

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

	Postretirement Benefits		
	2011	2010	2009
Weighted average assumptions:			
Discount rate, postretirement expense	5.08 %	5.50 %	6.00 %
Discount rate, projected benefit obligation	4.04	5.08	5.50
Expected return on plan assets	6.50	6.50	6.50
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, 2011 and 2010:

Asset Class	Fair Value 2011	Fair Value 2010	Target 2011	Target 2010
Cash and equivalents	$ 10,615	$ 118,858	1 %	16 %
Equities	698,800	553,043	76	73
Fixed income	206,599	79,746	23	11
Total	$ 916,014	$ 751,647	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 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. Plan investments held at December 31, 2011, are classified as Level 1 based on the fair value hierarchy discussed in Note 13.

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 $3,986,446 and $3,770,968 at December 31, 2011 and 2010, 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 3.05%, 3.925%, and 5.0%, and a rate of compensation increase of 3.0% at December 31, 2011, 2010, and 2009. Aggregate benefits payable amounted to $3,571,748 and $3,690,898 at December 31, 2011 and 2010, respectively, and are included in deferred compensation in the consolidated balance sheet.

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, 2011 and 2010, is $1,396,988 and $1,145,278, respectively.

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 $524,311, $518,174, and $378,615 in 2011, 2010, and 2009, respectively.

10. 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), prior to 2011. VETCO operates 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. VELCO previously determined that it did not have a controlling financial interest in VETCO, as VELCO was not exposed to the risks and rewards of VETCO. Therefore VELCO did not consolidate its financial information with that of VETCO and, instead accounted for its investment using the equity method.

In 2011, the Company considered the ability of the Board of Directors of VELCO to influence the day to day management of the activities which most significantly impact VETCO, and their ownership of VETCO, and determined VELCO was the primary beneficiary of VETCO, and consolidated the balance sheet and results of VETCO for the year ended December 31, 2011. Management determined the impact on the prior years was immaterial.

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, 2011, VETCO has returned to VELCO $9,850,000 of the original capital contribution. The carrying amount of the investment was $560,108 at December 31, 2010.

Summarized financial information related to VETCO at December 31, 2010, and for the two years then ended is as follows:

	Balance Sheet 2010
Net utility plant in service	$2,247,805
Other assets	940,281
Total assets	$3,188,086
Other liabilities	$2,627,979
Stockholders' investment	560,107
Total liabilities and stockholders' investment	$3,188,086

	Statement of Income 2010	2009
Operating revenues	$ 2,017,644	$ 1,908,177
Operating expenses	(1,932,053)	(1,864,755)
Interest expense	(11,914)	(13,965)
Net income	$ 73,677	$ 29,457

Other Activity — VELCO has contracted with VETCO to provide VETCO with management and support services. In connection therewith, VELCO has charged VETCO $1,157,353 in 2010 and $996,437 in 2009, 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 $190,000. As per the agreement, VETCO agrees to pay interest monthly at a rate charged by KeyBank National Association pursuant to the VELCO and VT Transco Line of Credit Agreement. The balance outstanding at December 31, 2010 was $125,000.

11. 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 $2,413,920, $479,844, and $465,075 in 2011, 2010, and 2009, 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 $58,073, $1,583,140, and $1,775,411, in 2011, 2010, and 2009, respectively.

12. 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 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 of $8,794,375 and $4,666,950, in 2011 and 2010, respectively, is included as a component of regulatory liabilities in the consolidated balance sheet.

13. 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, 2011 and 2010. 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.

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial liabilities:				
First mortgage bonds	$297,483,000	$354,996,006	$317,272,000	$328,376,057

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, 2011 and 2010, 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.

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, line of credit to banks, accounts payable, accrued interest on bonds, current maturities of long-term obligations, and accrued expenses have been excluded from the table above as they approximate the carrying amounts due to their short-term nature.

- Notes receivable: Because of the short-term maturity of this instrument, carrying value 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, 2011 and 2010, the Company utilized Moody's long term corporate bond yield average for utility entities with an Aa rating to determine fair value.

Fair Value Hierarchy — The Company follows ASC Topic 820, *Fair Value Measurements and Disclosures* 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 financial statements on a recurring or 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 non-financial assets or liabilities reported at fair value at December 31, 2010.

Recurring Measures — The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that are accounted for at fair value on a recurring basis. The Company's 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:

	For the Year Ended December 31, 2011			
	Level 1	Level 2	Level 3	Total
Liabilities				
Interest rate swap	$ -	$ 1,059,385	$ 0	$ 1,059,385

Interest rate swap agreements are based on LIBOR and the value is determined using a pricing model with inputs derived from observable market data.

14. BUSINESS AND CREDIT CONCENTRATIONS

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, 2011 and 2010:

	2011	2010
ISO New England	23.0 %	41.0 %
CVPS	28.4	24.0
GMP	22.9	18.0
	74.3 %	83.0 %

Significant Capital Projects — The Company is in the process of performing construction projects to enhance services to its customers. These projects have been a major focus for the Company during 2011 and 2010. Costs capitalized amounted to approximately $70,500,000, $117,000,000, and $163,000,000 in 2011, 2010, and 2009, respectively. The Company has budgeted $123,000,000 for 2012 related to capital projects which will be financed through bond issuance and borrowings on the line of credit.

15. FEDERAL STIMULUS FUNDS

On October 27, 2009, the US Department of Energy announced that Vermont's electric utilities will receive $69,000,000 in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation. As the prime recipient of Vermont's smart grid stimulus application, the Company expects to receive a grant of over $3,000,000 to manage the overall project on behalf of the Vermont Distribution Utilities. The agreement includes provisions for funding and other requirements. The agreement became effective on April 19, 2010. The Company is eligible to receive reimbursement of 50% of the total project costs incurred from August 6, 2009, up to $3,000,000. For the years ended December 31, 2011, 2010, and 2009, $629,000, $1,100,000, and $0 respectively, of expenses were incurred. These expenses and the related reimbursements are included as a component of other (income) expense in the accompanying consolidated statements of income. The Company has submitted requests for reimbursement of $769,000 and have received $683,000 to date. The 50% of costs not reimbursed by the DOE are billed to the Vermont Distribution Utilities that are sub-recipients of the grant.

16. COMMITMENTS

The Company reached a settlement with the Lamoille County municipal distribution utilities in 2008, 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.

17. SUBSEQUENT EVENTS

Management has evaluated subsequent events occurring through March 13, 2012, the date that these financial statements were issued, and determined that no additional subsequent events occurred that would require recognition or disclosure in these financial statements.

* * * * * *

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Vermont Electric Power Company, Inc.
Rutland, Vermont

We have audited the accompanying consolidated balance sheet of Vermont Electric Power Company, Inc. and subsidiaries (the "Company") as of December 31, 2011, and the related consolidated statements of income, stockholders' equity, and cash flows for the year then ended. 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included 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, such 2011 consolidated financial statements present fairly, in all material respects, the financial position of Vermont Electric Power Company, Inc. and subsidiaries as of December 31, 2011, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

March 13, 2012

EXHIBIT 99.2

Vermont Transco LLC

Financial Statements as of December 31, 2011
and 2010, and for Each of the Years in the
Three-Year Period Ended December 31, 2011
and Report of Independent Registered Public
Accounting Firm

VERMONT TRANSCO LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Vermont Electric Power Company, Inc as
Manager of Vermont Transco LLC:

We have audited the accompanying balance sheet of Vermont Transco LLC (the "Company") as of December 31, 2011, and the related statements of income, changes in members' equity, and cash flows for the year then ended. 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 audit. The consolidated financial statements of the Company for the year ended December 31, 2010 and 2009 were audited by other auditors whose report, dated March 8, 2011, expressed an unqualified opinion on those statements.

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 the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included 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 audit provides a reasonable basis for our opinion.

In our opinion, such 2011 financial statements present fairly, in all material respects, the financial position of Vermont Transco LLC as of December 31, 2011, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

March 13, 2012

VERMONT TRANSCO LLC

BALANCE SHEETS
AS OF DECEMBER 31, 2011 AND 2010

ASSETS	2011	2010
UTILITY PLANT	$ 912,037,572	$ 841,651,793
LESS ACCUMULATED DEPRECIATION AND AMORTIZATION	(125,737,699)	(107,263,675)
Net utility plant	786,299,873	734,388,118
NONUTILITY PLANT	2,411,563	
CURRENT ASSETS:		
Cash	9,063,842	2,066,045
Restricted cash	1,178,875	
Bond sinking fund deposits	12,571,333	564,000
Bond interest deposits	2,922,933	4,537,947
Accounts receivable:		
Affiliated companies	4,354,979	
Other	10,673,551	8,967,385
Due from Vermont Electric Power Company, Inc.	2,966,491	9,767,793
Note receivable — related party		125,000
Materials and supplies	7,918,387	7,333,500
Prepaids and other assets	1,772,283	1,143,965
Total current assets	53,422,674	34,505,635
REGULATORY AND OTHER ASSETS:		
Regulatory assets	3,088,185	3,659,535
Unamortized debt expense — net	2,417,295	2,563,063
Deferred project costs and other	4,514,651	5,740,634
Total regulatory and other assets	10,020,131	11,963,232
TOTAL ASSETS	$ 852,154,241	$ 780,856,985

(Continued)

VERMONT TRANSCO LLC

BALANCE SHEETS
AS OF DECEMBER 31, 2011 AND 2010

CAPITALIZATION AND LIABILITIES	2011	2010
CAPITALIZATION:		
Members' equity	$424,565,430	$406,915,930
Mandatorily redeemable membership units	10,000,000	10,000,000
First mortgage bonds — net of current maturities	297,483,000	317,272,000
Total capitalization	732,048,430	734,187,930
COMMITMENTS AND CONTINGENCIES (Notes 8, 12, and 14)		
CURRENT LIABILITIES:		
Bank overdraft	1,433,309	891,788
Current maturities of long-term obligations	19,789,000	11,821,000
Line of Credit to bank	52,701,113	
Accounts payable:		
Affiliated companies	1,872,610	1,236,182
Other	13,439,598	7,182,351
Accrued interest	4,452,717	4,563,321
Accrued construction expenses	7,022,409	4,699,609
Accrued expenses	1,422,030	2,781,167
Total current liabilities	102,132,786	33,175,418
LONG-TERM LIABILITIES:		
Deferred cost of removal liabilities	8,794,375	4,732,373
Deferred income	1,243,840	660,920
Due to Vermont Electric Power Company, Inc.	7,934,810	8,100,344
Total liabilities	120,105,811	46,669,055
TOTAL CAPITALIZATION AND LIABILITIES	$852,154,241	$780,856,985

See notes to financial statements.

(Concluded)

VERMONT TRANSCO LLC

STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	2011	2010	2009
OPERATING REVENUES:			
Transmission revenues	$ 134,135,239	$ 102,547,684	$ 90,649,734
Rent of transmission facilities to others	994,277	999,587	2,435,380
	135,129,516	103,547,271	93,085,114
OPERATING EXPENSES:			
Transmission expenses:			
Operations	4,741,619	4,069,124	3,369,434
Maintenance	7,019,000	6,490,760	5,625,653
Charges for transmission facilities of others	50,860	44,183	41,705
Administrative and general expenses	6,982,529	5,581,386	7,718,153
Depreciation and amortization	20,849,266	16,031,969	13,942,091
Taxes other than income	14,985,771	11,445,565	10,485,062
Total operating expenses	54,629,045	43,662,987	41,182,098
Operating income	80,500,471	59,884,284	51,903,016
OTHER (INCOME) EXPENSES:			
Interest on first mortgage bonds	17,921,196	18,197,213	13,477,726
Other interest expense	434,478	803,189	1,057,144
Amortization of debt expense	145,769	148,791	101,560
Allowance for borrowed funds used during construction	(1,000,138)	(4,394,038)	(2,151,956)
Allowance for equity funds during construction	(1,518,157)	(6,566,209)	(2,977,719)
Other	129,940	114,130	12,712
Interest and other income	(36,164)	(267,338)	(239,474)
Total other expenses — net	16,076,924	8,035,738	9,279,993
INCOME BEFORE TAX	$ 64,423,547	$ 51,848,546	$ 42,623,023

See notes to financial statements.

VERMONT TRANSCO LLC

STATEMENTS OF CHANGES IN MEMBERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	Membership Units				Accumulated	Total Members'
	Units	Class A	Units	Class B	Earnings	Equity
BALANCES — December 31, 2008	19,891,672	$ 198,916,720	3,151,638	$ 31,516,380	$ 19,245,281	$ 249,678,381
Issuance of membership units	4,480,877	44,808,770	1,523,902	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 — December 31, 2009	24,372,549	243,725,490	4,675,540	46,755,400	34,988,543	325,469,433
Issuance of membership units	6,168,730	61,687,300	627,498	6,274,980		67,962,280
Income before tax					51,848,546	51,848,546
Distribution of income before tax to members					(38,364,329)	(38,364,329)
BALANCES — December 31, 2010	30,541,279	305,412,790	5,303,038	53,030,380	48,472,760	406,915,930
Issuance of membership units	56,005	560,050	58,995	589,950		1,150,000
Income before tax					64,423,547	64,423,547
Distribution of income before tax to members					(47,924,047)	(47,924,047)
BALANCES — December 31, 2011	30,597,284	$ 305,972,840	5,362,033	$ 53,620,330	$ 64,972,260	$ 424,565,430

See notes to financial statements.

VERMONT TRANSCO LLC

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income before tax	$ 64,423,547	$ 51,848,546	$ 42,623,023
Adjustments to reconcile income before tax to net cash provided by operating activities:			
Depreciation and amortization	20,277,916	15,460,619	13,370,741
Amortization of regulatory assets	571,350	571,350	571,350
Amortization of debt expense	145,769	148,791	101,560
Changes in assets and liabilities:			
Accounts receivable	(6,061,144)	(65,520)	(1,517,900)
Materials and supplies	(584,887)	(1,084,504)	435,812
Accounts payable	3,090,451	(4,389,293)	3,772,475
Due from related party			(311,153)
Other assets and liabilities	1,548,520	(3,276,130)	1,975,888
Net cash provided by operating activities	83,411,522	59,213,859	61,021,796
CASH FLOWS FROM INVESTING ACTIVITIES:			
Change in bond sinking fund deposits	(12,007,333)	(38,000)	(36,000)
Capital expenditures, including interest capitalized	(64,520,576)	(121,558,292)	(166,183,460)
Repayments of (Advances to) related party notes receivable	125,000	10,800,000	(225,000)
Net cash used in investing activities	(76,402,909)	(110,796,292)	(166,444,460)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Change in bank overdraft	541,521	(2,083,243)	1,380,293
Proceeds from bond issuance			135,000,000
Repayment of bonds	(11,821,000)	(2,161,000)	(2,014,000)
Debt issue costs		311	(1,014,724)
Borrowings of Line of Credit to bank	52,701,113		
Repayments of Line of Credit to bank			(20,857,520)
Repayment of other long-term debt		(152,115)	(292,121)
Due from Vermont Electric Power Company, Inc.	6,635,768	27,713,424	(39,287,043)
Issuance of membership units	1,150,000	67,962,280	60,047,790
Distribution of income before tax to members	(47,924,047)	(38,364,329)	(26,879,761)
Net cash provided by financing activities	1,283,355	52,915,328	106,082,914
NET INCREASE IN CASH	8,291,968	1,332,895	660,250
CASH — Beginning of year	771,874	733,150	72,900
CASH — End of year	$ 9,063,842	$ 2,066,045	$ 733,150
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION — Cash paid for interest — net of amounts capitalized	$ 15,947,983	$ 8,052,319	$ 7,830,970

NONCASH ACTIVITY — In 2011, 2010, and 2009, the Company recorded accounts payable related to capital expenditures and accrued construction expenses of $6,018,659, $7,725,685, and ($337,977), respectively.

See notes to financial statements.

1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

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:

	2011	2010
Vermont Electric Power Company, Inc. (VELCO)	9 %	9 %
Central Vermont Public Service Corporation (CVPS)	37	37
Green Mountain Power Company (GMP)	28	28
Vermont Public Power Supply Authority (VPPSA)	11	11

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.

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.

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 $1,701,555 and $2,126,944 as of December 31, 2011 and 2010, 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 $1,386,630 and $1,532,591 as of December 31, 2011 and 2010, respectively.

As more fully described in note 8, 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 Manager's regulatory asset related to these plans totaled $10,949,323 and $5,390,601 at December 31, 2011 and 2010, 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents — We consider all liquid investments with an original maturity of three months or less when acquired to be cash and cash equivalents.

Restricted Cash — We have restricted cash related to a settlement agreement and a vendor contract, and consists of cash in banks.

Bond Sinking Fund and Interest Deposits — The terms of our bond agreements require that interest and principal be deposited monthly into these deposit accounts. The interest and principal is paid on a quarterly basis. These deposits consist of cash and cash equivalents in banks.

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. The 1991 Vermont Transmission Agreement 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 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 $402,010 at December 31, 2011 and 2010, respectively, and has been reported in prepaids and other assets in the accompanying financial statements.

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 3 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, 2011, 2010 and 2009 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.

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.

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 6.37%, 7.50%, and 5.75% in 2011, 2010 and 2009, respectively.

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

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 $145,769, $148,791, and $101,560 in 2011, 2010 and 2009, respectively.

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.

The Company provides reserves for potential payments of tax to various tax authorities related to uncertain tax positions. Reserves are based on a determination of whether and how much of a tax benefit taken by the Company in its tax filings or positions is more likely than not to be realized following resolution of the uncertainty. Potential interest and penalties associated with such uncertain tax positions is recorded as a component of interest and administrative and general expense, respectively. Through December 31, 2011, the Company has not identified any material uncertain tax positions.

Pension and Other Postretirement Plans — 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 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.

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 valuation 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.

Fair Value Measurements — The fair values of cash, accounts receivable, accounts payable, accrued expenses, and line of credit approximate the carrying amounts due to their short-term nature. (note 11).

Concentrations of Credit Risk — Financial instruments that subject the Company to significant concentrations of credit risk consist primarily of cash and bond sinking fund deposits. Substantially, all of the Company's cash is held at one financial institution that management believes to be of high-credit quality.

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.

Government Grants — The Company recognizes government grants when there is reasonable assurance that the Company will comply with the conditions attached to the grant arrangement and the grant will be received. Government grants are recognized in the income statement over the periods in which we recognize the related costs for which the government grant is intended to compensate.

When government grants are related to the oversight of sub-recipients, the grants are recognized as other income in the income statement. For government grants related to reimbursements of capital expenditures, the grants are recognized as a reduction of the basis of the asset and recognized in the Income Statement over the estimated useful life of the depreciable asset as reduced depreciation expense. For government grants related to billings from sub-recipients, the grants are recognized as receivables from the government agency and payables to the sub-recipient on the balance sheet as we do not have rights to the funds passing through to sub-recipients. The Company recorded government grants receivable on the balance sheet in prepaid and other assets for $70,000 in 2011.

3. UTILITY PLANT

Utility plant consists of the following at December 31, 2011 and 2010:

	2011	2010
Land and rights of way	$ 49,805,114	$ 80,148,733
Transmission equipment	694,619,856	657,074,976
Communications equipment	37,933,929	22,542,074
Buildings and office equipment	72,139,234	59,813,941
Construction work-in-process	57,539,439	22,072,069
	912,037,572	841,651,793
Less accumulated depreciation and amortization	125,737,699	107,263,675
	$ 786,299,873	$ 734,388,118

Depreciation and amortization expense was $20,277,916, $15,460,619, and $13,370,741 as of December 31, 2011, 2010 and 2009, respectively.

4. 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 2011, 2010 and 2009, each member was issued additional membership units in proportion to the value of cash it contributed to the Company for a total of $1,150,000, $67,962,280, and $60,047,790, respectively, in Class A and Class B Membership units. See Note 14 for discussion of the $10,000,000 of mandatorily redeemable membership units issued to the Manager in 2008.

Member's equity as of December 31, 2011, and 2010 is as stated in the table that follows.

	2011	2010
Village of Morrisville	$ 1,311,865	$ 1,311,868
Swanton Village	612,110	612,110
Vermont Electric Cooperative	9,207,949	9,089,123
Washington Electric Cooperative	4,326,517	4,305,483
Central Vermont Public Service Corporation	164,728,479	156,337,602
Village of Stowe	22,040,096	22,011,714
Village of Northfield	306,502	306,502
Green Mountain Power Corporation	128,495,492	122,298,889
City of Burlington Electric Department	18,739,950	17,589,949
Village of Hyde Park	139,561	139,561
Vermont Electric Power Company, Inc.	32,632,645	30,971,485
Village of Lyndonville	135,096	131,000
Vermont Public Power Supply Authority	41,889,168	41,810,644
	$ 424,565,430	$ 406,915,930

Distribution of income before tax to members is at the discretion of the Manager. During 2011, 2010 and 2009, the Company distributed $47,924,047, $38,364,329, and $26,879,761, respectively, of its income before tax to its member in proportion to each member's percentage interest in the Company.

5. 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.

First Mortgage Bonds — The Company's First Mortgage Bonds outstanding include the following series at December 31, 2011 and 2010:

	2011	2010
Series L, 7.30% due through 2018	$ 6,054,000	$ 6,758,000
Series N, 7.42%, due through 2012	18,557,000	19,727,000
Series O, 6.26% due through 2034	22,161,000	22,608,000
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	125,500,000	135,000,000
	317,272,000	329,093,000
Less bonds to be retired within one year	19,789,000	11,821,000
	$ 297,483,000	$ 317,272,000

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:

2012	$ 19,789,000
2013	11,821,000
2014	13,916,000
2015	14,513,000
2016	15,621,000
Thereafter	241,612,000
Total	$317,272,000

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 $105,757,333 at December 31, 2011. Interest recorded for the First Mortgage Bonds in 2011, 2010 and 2009 was $17,921,196, $18,197,213, and $13,477,726, respectively.

6. LINE OF CREDIT

The Company has an unsecured $100,000,000 line-of-credit agreement with a financial institution, reduced by certain standby letters of credit totaling $325,000, expiring on April 30, 2012 to provide interim financing for utility plant construction. The line is renewed each year for a one year term. The Company plans to refinance the line of credit when it comes due on April 30, 2012. If the Company is unable to obtain the line of credit, it has the ability to issue an equity call to its members. The Company's Manager is also an obligor on this facility. As part of this agreement, the Company agrees to pay 0.10% per annum on the daily unused line of credit amount. The interest rate at December 31, 2011 is at the Company's option of either LIBOR plus .75% for 30, 60 or 90 days or overnight LIBOR plus 1.00%. Average daily borrowing was $19,610,628 in 2011 and $23,926,753 in 2010 at a weighted average interest rate of 1.73% and 2.72%, respectively. At December 31, 2011 $62,701,113 was outstanding under the agreement, of which $52,701,113 was recorded on the Company's financial statements. The Company and VELCO are jointly liable for the $62,701,113 amount outstanding at December 31, 2011. At December 31, 2010 there were no amounts outstanding under the agreement. Interest recorded for these borrowings in 2011, 2010 and 2009 was $340,311, $650,707 and $832,623, respectively.

7. 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

$58,260,000 in 2011 and $45,700,000 in 2010, and are primarily related to accelerated tax depreciation and other plant-related differences and VELCO's portion is included in liability due to VELCO of $14,446,133 in 2011 and $12,498,349 in 2010.

8. 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 in future customer rates, in which case it would be recorded as a regulatory asset. As of December 31, 2011 and 2010, the Manager recorded a regulatory asset of $10,041,650 and $4,546,992, respectively, an unfunded defined pension obligation of $10,428,405 and $4,934,040, respectively, and a postretirement healthcare obligation of $948,809 and $883,735, respectively, and related regulatory asset of $907,673 and $843,609, respectively. Such amounts are reported in due to VELCO in the accompanying balance sheets.

Defined Benefit Plan — The Manager sponsors a defined benefit pension plan (the Plan) covering employees of the Manager 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.

The following sets forth the Plan's benefit obligations, fair value of plan assets and funded status at December 31, 2011 and 2010:

	Pension Benefits	
	2011	2010
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 20,023,874	$ 17,171,882
Service cost	1,039,809	1,013,619
Interest cost	1,088,484	1,008,694
Actuarial loss	5,033,150	1,363,118
Benefits paid	(505,554)	(533,439)
Benefit obligation at end of year	26,679,763	20,023,874
Change in plan assets:		
Fair value of plan assets at beginning of year	15,089,834	12,875,783
Actual return on plan assets	542,078	1,722,490
Employer contribution	1,125,000	1,025,000
Benefits paid	(505,554)	(533,439)
Fair value of plan assets at end of year	16,251,358	15,089,834
Funded status	$ (10,428,405)	$ (4,934,040)
Accumulated benefit obligation	$ 19,264,336	$ 14,680,249

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2011 and 2010, which are recorded as a regulatory asset, are as follows:

	2011	2010
Net actuarial loss	$ 9,759,843	$4,217,808
Unrecognized prior service cost	281,808	329,184
	$10,041,651	$4,546,992

The amount of the regulatory asset expected to be recognized as a component of net periodic pension cost in 2012 is $164,734.

Net periodic benefit cost for the years ended December 31, 2011, 2010 and 2009 are as follows:

	Pension Benefits		
	2011	2010	2009
Components of net periodic benefit cost:			
Service cost	$ 1,039,809	$ 1,013,619	$ 1,016,923
Interest cost	1,088,484	1,008,694	944,414
Expected return on plan assets	(1,168,321)	(1,078,827)	(1,026,169)
Recognized net actuarial loss	117,357	28,974	11,235
Net amortization	47,377	52,476	52,476
Net periodic benefit cost	$ 1,124,706	$ 1,024,936	$ 998,879

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

Weighted-average assumptions:			
Discount rate — pension expense	5.56 %	6.00 %	6.00 %
Discount rate — projected benefit obligation	4.40	5.56	6.00
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 2012 to 2016 and the aggregate benefits to be paid in the five years from 2017 to 2021 are as follows:

Fiscal Year Ending December 31	Pension Benefit Payments
2012	$ 429,613
2013	482,816
2014	556,674
2015	550,672
2016	558,620
2017–2021	4,387,626
Expected contribution for next fiscal year	1,125,000

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, 2011 and 2010:

Asset Class	Plan Assets 2011	Plan Assets 2010	Asset Allocation 2011	Asset Allocation 2010
Money market	$ 2,480,407	$ 1,348,099	15 %	9 %
Equities	8,283,812	9,306,708	51	62
Fixed income	5,487,139	4,435,017	34	29
Total	$ 16,251,358	$ 15,089,824	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. Plan investments held at December 31, 2011 are classified as Level 1 based on the fair value hierarchy discussed in note 11.

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, 2011, 2010 and 2009, the Manager contributed $150,213, $131,129, and $32,141, respectively, toward these benefits. The Company anticipates contributing $180,000 for these benefits in 2012.

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 following sets forth the Plan's benefit obligations, fair value of plan assets and funded status at December 31, 2011 and 2010:

	Postretirement Benefits	
	2011	2010
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 1,635,382	$ 1,496,132
Service cost	111,908	107,413
Interest cost	80,173	81,284
Actuarial loss	88,310	128,721
Benefits paid	(50,950)	(178,168)
Benefit obligation at end of year	1,864,823	1,635,382
Change in plan assets:		
Fair value of plan assets at beginning of year	751,647	573,400
Actual return on plan assets	14,154	47,118
Employer contribution — net of reimbursement from VEBA	201,163	309,297
Benefits paid	(50,950)	(178,168)
Fair value of plan assets at end of year	916,014	751,647
Funded status	$ (948,809)	$ (883,735)

Items not yet recognized as a component of net periodic benefit cost as of December 31, 2011 and 2010, which are recorded as a regulatory asset, are as follows:

	2011	2010
Change in measurement date to be recovered in rates	$ 16,676	$ 38,910
Net actuarial loss	890,997	804,699
	$ 907,673	$ 843,609

The amount of the regulatory asset expected to be recognized as a component of net periodic benefit cost in 2012 is $63,824.

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 $9,772 and a 1.0% decrease in the trend rate would decrease the postretirement accumulated benefit obligation by $9,210 in 2012.

Net periodic benefit costs as of December 31, 2011, 2010, and 2009 are as follows:

	Postretirement Benefits		
	2011	2010	2009
Components of net periodic benefit cost:			
Service cost	$ 111,908	$ 107,413	$ 93,871
Interest cost	80,173	81,284	82,303
Expected return on plan assets	(53,732)	(42,747)	(40,515)
Recognized net actuarial loss	22,234	22,234	22,234
Net amortization	41,590	37,768	32,953
Net periodic benefit cost	$ 202,173	$ 205,952	$ 190,846

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

	Postretirement Benefits		
	2011	2010	2009
Weighted-average assumptions:			
Discount rate — postretirement benefit	5.08 %	5.50 %	6.25 %
Discount rate — projected benefit obligation	4.04	5.08	5.50
Expected return on plan assets	6.50	6.50	6.50
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, 2011 and 2010:

	Plan Assets		Asset Allocation	
Asset Class	2011	2010	2011	2010
Cash and equivalents	$ 10,615	$ 118,858	1 %	16 %
Equities	698,800	553,043	76	73
Fixed income	206,599	79,746	23	11
Total	$ 916,014	$ 751,647	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. Plan investments held at December 31, 2011 are classified as Level 1 based on the fair value hierarchy discussed in Note 11.

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 $3,986,446 and $3,770,968 at December 31, 2011 and 2010, 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 3.05%, 3.925%, and 5.00%, and a rate of compensation increase of 3% at December 31, 2011, 2010, and 2009. Aggregate benefits payable amounted to $3,571,748 and $3,690,898 at December 31, 2011 and 2010, respectively, and is recorded in due to VELCO.

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, 2011 and 2010 is $1,396,988 and $1,145,278, respectively, and is recorded in due to VELCO.

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 $524,311, $518,174, and $378,615 in 2011, 2010 and 2009, respectively.

9. RELATED-PARTY TRANSACTIONS

Amounts included in due from related party at December 31, 2011 and 2010 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 $190,000. The balance outstanding at December 31, 2011 and 2010 was $0 and $125,000, 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 $2,413,920, $479,844 and $465,075 in 2011, 2010 and 2009, 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 $58,073, $1,583,140 and $1,775,411 in 2011, 2010 and 2009, respectively.

10. 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 $8,794,375 and $4,732,373 in 2011 and 2010, respectively.

11. 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, 2011 and 2010. 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.

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial liabilities:				
First mortgage bonds	$297,483,000	$354,996,006	$317,272,000	$328,376,057

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, 2011 and 2010 represent management's best estimates of the amounts 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.

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 receivable, line of credit to banks, accounts payable, accrued interest on bonds due from (to) VELCO, current maturities of long-term obligations, and construction and other accrued expenses have been excluded from the table above as they approximate the carrying amounts due to their short-term nature.

- 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, 2011 and 2010, the Company utilized Moody's long-term corporate bond yield average for utility entities with an Aa rating.

Fair Value Hierarchy:

The Company follows FASB ASC 820 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 and non-recurring 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 non-financial assets and liabilities reported at fair value at 2011 or 2010.

12. BUSINESS AND CREDIT CONCENTRATIONS

Significant Customers — One customer, ISO New England individually represents 49% and 98% of total accounts receivable and 77% and 100% of total revenue at December 31, 2011 and 2010, respectively.

Significant Capital Projects — The Company is in the process of performing construction projects to enhance services to its customers. Costs capitalized amounted to approximately $70,500,000 and $117,000,000 in 2011 and 2010, respectively. The Company has budgeted $123,000,000 for 2012 related to capital projects which will be financed through bond issuance and borrowings on the line of credit.

13. FEDERAL STIMULUS FUNDS

On October 27, 2009, the US Department of Energy announced that Vermont's electric utilities will receive $69,000,000 in federal stimulus funds to deploy advanced metering, new customer service enhancements, and grid automation. As the prime recipient of Vermont's Smart Grid stimulus application, the Company expects to receive a grant of over $3,000,000 to manage the overall project on behalf of the Vermont Distribution Utilities. The agreement includes provisions for funding and other requirements. The agreement became effective on April 19, 2010. The Company is eligible to receive reimbursement of 50 percent of the total project costs incurred from August 6, 2009, up to $3 million. For the years ended December 31, 2011 and 2010, $629,000 and $1,100,000, respectively, of operating expenses were incurred. These expenses and the related reimbursements are included as a component of other (income) expense in the accompanying statements of income. The Company has submitted requests for reimbursement of $769,000 and have received $683,000 to date. The 50% of costs not reimbursed by the DOE are billed to the Vermont Distribution Utilities that are sub-recipients of the grant.

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 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 $33,421,303 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.

15. SUBSEQUENT EVENTS

Management has evaluated subsequent events occurring through March 13, 2012, the date these financial statements were issued, and determined that no additional subsequent events occurred that would require recognition or disclosure in these financial statements.

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