UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 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 **1-8222**

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

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

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

N/A
(Former name, former address and former fiscal year, if changed since last report)

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

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

Indicate by check mark 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 Exchange Act).
Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. As of April 29, 2011 there were outstanding 13,397,982 shares of Common Stock, $6 Par Value.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
Form 10-Q for Period Ended March 31, 2011

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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
FTRs	Financial Transmission Rights
GMP	Green Mountain Power Corporation

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three months ended March 31	
	2011	2010
Operating Revenues	**$97,085**	$91,007
Operating Expenses		
Purchased Power - affiliates	**17,411**	16,558
Purchased Power	**23,941**	25,160
Production	**3,144**	2,956
Transmission - affiliates	**2,257**	1,386
Transmission - other	**7,104**	7,187
Other operation	**18,594**	15,846
Maintenance	**5,707**	7,726
Depreciation	**4,485**	4,352
Taxes other than income	**4,657**	4,743
Income tax expense	**2,857**	1,838
Total Operating Expenses	**90,157**	87,752
Utility Operating Income	**6,928**	3,255
Other Income		
Equity in earnings of affiliates	**6,941**	5,395
Allowance for equity funds during construction	**56**	3
Other income	**703**	712
Other deductions	**(654)**	(679)
Income tax expense	**(2,302)**	(1,589)
Total Other Income	**4,744**	3,842
Interest Expense		
Interest on long-term debt	**3,144**	2,786
Other interest	**129**	111
Allowance for borrowed funds during construction	**(26)**	(2)
Total Interest Expense	**3,247**	2,895
Net Income	**8,425**	4,202
Dividends declared on preferred stock	**92**	92
Earnings available for common stock	**$8,333**	$4,110
Per Common Share Data:		
Basic earnings per share	**$0.62**	$0.35
Diluted earnings per share	**$0.62**	$0.35
Average shares of common stock outstanding - basic	**13,353,973**	11,725,484
Average shares of common stock outstanding - diluted	**13,406,926**	11,756,303
Dividends declared per share of common stock	**$0.46**	$0.46

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(dollars in thousands)
(unaudited)

	Three months ended March 31	
	2011	2010
Net Income	**$8,425**	$4,202
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 and $0	**95**	0
Change in funded status of pension, postretirement medical and other benefit plans, net of income taxes of $26 and $0	**38**	0
Comprehensive income adjustments	**133**	0
Total comprehensive income	**$8,558**	$4,202

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

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

Cash flows provided (used) by:	Three months ended March 31 2011	2010
OPERATING ACTIVITIES		
Net income	**$8,425**	$4,202
Adjustments to reconcile net income to net cash provided by operating activities:		
Equity in earnings of affiliates	**(6,941)**	(5,395)
Distributions received from affiliates	**3,562**	2,689
Depreciation	**4,485**	4,352
Deferred income taxes and investment tax credits	**2,057**	848
Regulatory and other amortization, net	**4,104**	1,129
Non-cash employee benefit plan costs	**1,761**	1,576
Other non-cash expense and (income), net	**(2,833)**	421
Changes in assets and liabilities:		
Decrease in accounts receivable and unbilled revenues	**6,584**	1,697
Increase in accounts payable	**599**	86
Change in prepaid and accrued income taxes	**14,349**	10,791
Increase in other current assets	**(803)**	(3,066)
Decrease in special deposits and restricted cash for power collateral	**0**	5,370
Employee benefit plan funding	**(8)**	(76)
(Decrease) increase in other current liabilities	**(3,032)**	162
Decrease in other long-term assets and liabilities and other	**73**	156
Net cash provided by operating activities	**32,382**	24,942
INVESTING ACTIVITIES		
Construction and plant expenditures	**(10,004)**	(5,751)
Reimbursements of restricted cash - project fund investments	**7,004**	0
Project reimbursement from DOE	**375**	0
Investments in available-for-sale securities	**(345)**	(543)
Proceeds from sale of available-for-sale securities	**300**	464
Other investing activities	**(154)**	(177)
Net cash used for investing activities	**(2,824)**	(6,007)
FINANCING ACTIVITIES		
Net proceeds from the issuance of common stock	**361**	715
Decrease in special deposits for preferred stock mandatory redemption	**0**	1,000
Retirement of preferred stock subject to mandatory redemption	**0**	(1,000)
Common and preferred dividends paid	**(3,161)**	(2,787)
Proceeds from revolving credit facility and other short-term borrowings	**11,384**	45,255
Repayments under revolving credit facility and other short-term borrowings	**(25,079)**	(58,633)
Common stock offering and debt issue costs	**(128)**	(98)
Reduction in capital lease and other financing activities	**(482)**	(318)
Net cash used by financing activities	**(17,105)**	(15,866)
Net increase in cash and cash equivalents	**12,453**	3,069
Cash and cash equivalents at beginning of the period	**2,676**	2,069
Cash and cash equivalents at end of the period	**$15,129**	$5,138

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

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

	March 31, 2011 (unaudited)	December 31, 2010
ASSETS		
Utility plant		
Utility plant, at original cost	$622,063	$611,746
Less accumulated depreciation	269,439	266,649
Utility plant, at original cost, net of accumulated depreciation	352,624	345,097
Property under capital leases, net	4,183	4,425
Construction work-in-progress	15,509	20,234
Nuclear fuel, net	2,070	1,737
Total utility plant, net	374,386	371,493
Investments and other assets		
Investments in affiliates	174,893	171,514
Non-utility property, less accumulated depreciation ($3,186 in 2011 and $3,164 in 2010)	2,194	2,196
Millstone decommissioning trust fund	6,006	5,742
Restricted cash	14,403	17,581
Other	7,212	7,013
Total investments and other assets	204,708	204,046
Current assets		
Cash and cash equivalents	15,129	2,676
Restricted cash	2,093	5,903
Special deposits	6	6
Accounts receivable, less allowance for uncollectible accounts ($2,841 in 2011 and $2,649 in 2010)	24,976	28,552
Accounts receivable - affiliates, less allowance for uncollectible accounts	134	314
Unbilled revenues	17,463	21,003
Materials and supplies, at average cost	6,692	7,159
Prepayments	6,492	15,862
Deferred income taxes	3,642	4,501
Power-related derivatives	81	28
Regulatory assets	2,281	1,924
Other deferred charges - regulatory	0	2,078
Other deferred charges and other assets	470	0
Other current assets	1,017	1,114
Total current assets	80,476	91,120
Deferred charges and other assets		
Regulatory assets	37,433	38,552
Other deferred charges - regulatory	457	2,260
Other deferred charges and other assets	2,556	3,275
Total deferred charges and other assets	40,446	44,087
TOTAL ASSETS	$700,016	$710,746

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

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

	March 31, 2011 (unaudited)	December 31, 2010
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 15,497,216 issued and 13,368,143 outstanding at March 31, 2011 and 15,470,217 issued and 13,341,144 outstanding at December 31, 2010	**$92,983**	$92,821
Other paid-in capital	**94,497**	94,462
Accumulated other comprehensive loss	**(99)**	(232)
Treasury stock, at cost, 2,129,073 shares at March 31, 2011 and December 31, 2010	**(48,436)**	(48,436)
Retained earnings	**136,303**	134,113
Total common stock equity	**275,248**	272,728
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Long-term debt	**188,300**	188,300
Capital lease obligations	**3,237**	3,471
Total capitalization	**474,839**	472,553
Current liabilities		
Current portion of long-term debt	**20,000**	20,000
Accounts payable	**8,223**	8,137
Accounts payable - affiliates	**11,260**	11,835
Notes payable	**0**	13,695
Nuclear decommissioning costs	**1,468**	1,438
Other deferred credits - regulatory	**1,086**	1,108
Other current liabilities	**28,190**	30,763
Total current liabilities	**70,227**	86,976
Deferred credits and other liabilities		
Deferred income taxes	**83,819**	82,406
Deferred investment tax credits	**2,323**	2,387
Nuclear decommissioning costs	**4,998**	5,383
Asset retirement obligations	**3,676**	3,609
Accrued pension and benefit obligations	**31,606**	32,441
Other deferred credits - regulatory	**4,027**	3,886
Other deferred credits and other liabilities	**24,501**	21,105
Total deferred credits and other liabilities	**154,950**	151,217
Commitments and contingencies (Note 13)		
TOTAL CAPITALIZATION AND LIABILITIES	**$700,016**	$710,746

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

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

	Common Stock		Treasury Stock					
	Shares Issued	Amount	Shares	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
Balance, December 31, 2010	15,470,217	$92,821	(2,129,073)	($48,436)	$94,462	($232)	$134,113	$272,728
Net income							8,425	8,425
Other comprehensive income						133		133
Common Stock Issuance, net of issuance costs								0
Dividend reinvestment plan	16,313	98			263			361
Stock options exercised								0
Share-based compensation:								
Common & nonvested shares	4,699	28			(25)			3
Performance share plans	5,987	36			(207)			(171)
Dividends declared:								
Common - $0.46 per share							(6,143)	(6,143)
Cumulative non-redeemable preferred stock							(92)	(92)
Amortization of preferred stock issuance expense					4			4
Gain (Loss) on capital stock								0
Balance, March 31, 2011	15,497,216	$92,983	(2,129,073)	($48,436)	$94,497	($99)	$136,303	$275,248

	Common Stock		Treasury Stock					
	Shares Issued	Amount	Shares	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
Balance, December 31, 2009	13,835,968	$83,016	2,129,073	($48,436)	$72,179	($209)	$124,873	$231,423
Net income							4,202	4,202
Other comprehensive income								0
Common Stock Issuance, net of issuance costs					(203)			(203)
Dividend reinvestment plan	17,440	105			232			337
Stock options exercised	35,100	210			301			511
Share-based compensation:								
Common & nonvested shares								0
Performance share plans	15,121	91			(344)			(253)
Dividends declared:								
Common - $0.46 per share							(5,416)	(5,416)
Cumulative non-redeemable preferred stock							(92)	(92)
Amortization of preferred stock issuance expense					4			4
Gain (Loss) on capital stock					2		(2)	0
Balance, March 31, 2010	13,903,629	$83,422	2,129,073	($48,436)	$72,171	($209)	$123,565	$230,513

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS ORGANIZATION
General Description of Business Central Vermont Public Service Corporation ("we", "us", "CVPS" or the "company") is the largest electric utility in Vermont. We engage principally in the purchase, production, transmission, distribution and sale of electricity. We serve approximately 159,000 customers in 163 of the towns and cities in Vermont. Our Vermont utility operation is our core business. We typically generate most of our revenues through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-NE, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue generated from these sales helps to mitigate our power supply costs.

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
Basis of Presentation These unaudited financial statements have been prepared pursuant to the rules and regulations of the SEC and in accordance with U.S. GAAP. The accompanying unaudited condensed consolidated interim financial statements contain all normal, recurring adjustments considered necessary to present fairly the financial position as of March 31, 2011, and the results of operations and cash flows for the three months ended March 31, 2011 and 2010. 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 financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our annual report on Form 10K for the year ended December 31, 2010.

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 Condensed 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 Condensed 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.

Regulatory Accounting Our utility operations are regulated by the PSB, FERC and the Connecticut Department of Public Utility and Control, with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. As required, we prepare our financial statements in accordance with FASB's guidance for regulated operations. The application of this guidance results in differences in the timing of recognition of certain expenses from those of other businesses and industries. In order for us to report our results under the accounting for regulated operations, our rates must be designed to recover our costs of providing service, and we must be able to collect those rates from customers. If rate recovery of the majority of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, we would reassess whether this accounting standard should continue to apply to our regulated operations. In the event we determine that we no longer meet the criteria for applying the accounting for regulated operations, the accounting impact would be a charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, we believe future recovery of our regulatory assets is probable. Criteria that could give rise to the discontinuance of accounting for regulated operations include: 1) increasing competition that restricts a company's ability to establish prices to recover specific costs, and 2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. See Note 9 - Retail Rates and Regulatory Accounting for additional information.

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 10 - 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 Condensed 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 Condensed 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 Condensed Consolidated Statements of Income over the estimated useful life of the depreciable asset as reduced depreciation expense.

We record government grants receivable in the Condensed 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.

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

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

	March 31, 2011	December 31, 2010
Taxes	**$3,655**	$14,662
Insurance	**1,913**	412
Miscellaneous	**924**	788
Total	**$6,492**	$15,862

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

	March 31, 2011	December 31, 2010
Deferred compensation plans and other	**$4,622**	$2,596
Accrued employee-related costs	**2,853**	4,660
Other taxes and Energy Efficiency Utility	**3,934**	4,105
Cash concentration account - outstanding checks	**118**	2,358
Obligation under capital leases	**935**	942
Provision for rate refund	**1,736**	5,137
Accrued Interest	**4,007**	938
Miscellaneous accruals	**9,985**	10,027
Total	**$28,190**	$30,763

NOTE 3 - EARNINGS PER SHARE

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

	2011	2010
Numerator for basic and diluted EPS:		
Net income	$8,425	$4,202
Dividends declared on preferred stock	(92)	(92)
Net income available for common stock	$8,333	$4,110
Denominators for basic and diluted EPS:		
Weighted-average basic shares of common stock outstanding	13,353,973	11,725,484
Dilutive effect of stock options	23,089	17,141
Dilutive effect of performance shares	29,864	13,678
Weighted-average diluted shares of common stock outstanding	13,406,926	11,756,303

There were no outstanding stock options excluded from the diluted shares computation for the three months ended March 31, 2011 because all exercise prices were below the current average market price. Outstanding stock options of 153,017 were excluded from the computation of diluted shares for the three months ended March 31, 2010 because the prices were above the current average market price.

Outstanding performance shares totaling 47,306 for the three months ended March 31, 2011 were excluded from the computation of diluted shares as either the performance share measures were not met or there was an antidilutive impact as compared to 60,473 shares excluded for the three months ended March 31, 2010.

NOTE 4 - INVESTMENTS IN AFFILIATES

VELCO Summarized consolidated financial information for Velco consolidated for the three months ended March 31 follows (dollars in thousands):

	2011	2010
Operating revenues	$34,227	$25,773
Operating income	$19,715	$14,937
Income before non-controlling interest and income tax	$15,769	$12,535
Less members' non-controlling interest in income	14,537	11,450
Less income tax	467	(34)
Net income	$765	$1,119
Company's common stock ownership interest	47.05%	47.05%
Company's equity in net income	$360	$476

Accounts payable to Velco were $5.1 million at March 31, 2011 and $5.8 million at December 31, 2010.

Transco Summarized financial information for Transco, also included in VELCO consolidated financial information above, for the three months ended March 31 follows (dollars in thousands):

	2011	2010
Operating revenues	$34,411	$26,165
Operating income	$20,502	$15,458
Net income	$16,137	$13,078
Company's ownership interest	41.02%	33.35%
Company's equity in net income	$6,525	$4,857

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 $2.3 million for the three months ended March 31, 2011 and $1.4 million for the three months ended March 31, 2010. These amounts are included in Transmission - affiliates on our Condensed Consolidated Statements of Income. Accounts payable to Transco were $0.4 million at March 31, 2011 and there were no accounts payable due at December 31, 2010. Accounts receivable from Transco was $0.2 million at December 31, 2010.

VYNPC Summarized financial information for VYNPC (dollars in thousands):

	2011	2010
Operating revenues	$48,973	$46,595
Operating (loss) income	($253)	($1,069)
Net income	$91	$101
Company's common stock ownership interest	58.85%	58.85%
Company's equity in net income	$53	$60

VYNPC's revenues shown in the table above include sales to us of $17.1 million for the three months ended March 31, 2011 and $16.2 million for the three months ended March 31, 2010. These amounts are included in Purchased power - affiliates on our Condensed Consolidated Statements of Income. Accounts payable to VYNPC were $5.7 million at March 31, 2011 and $5.9 million at December 31, 2010.

Maine Yankee, Connecticut Yankee and Yankee Atomic We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. All three companies have completed plant decommissioning and the operating licenses have been amended by the NRC for operation of Independent Spent Fuel Storage Installations. All three remain responsible for safe storage of the spent nuclear fuel and waste at the sites until the DOE meets its obligation to remove the material from the sites. Our share of the companies' estimated costs are reflected on the Condensed Consolidated Balance Sheets as regulatory assets and nuclear decommissioning liabilities (current and non-current). These amounts are adjusted when revised estimates are provided. At March 31, 2011, we had regulatory assets of $0.6 million for Maine Yankee, $4.2 million for Connecticut Yankee and $1.7 million for Yankee Atomic. These estimated costs are being collected from customers through existing retail rate tariffs. Total billings from the three companies amounted to $0.4 million for the three months ended March 31, 2011 and $0.3 million for the three months ended March 31, 2010. These amounts are included in Purchased power - affiliates on our Condensed Consolidated Statements of Income.

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

On March 6, 2009, the three companies submitted their revised statement of claimed damages for the case on remand. Maine Yankee claimed $81.7 million through 2002, Connecticut Yankee claimed $39.7 million and Yankee Atomic claimed $53.9 million in damages through 2001.

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

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

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

In December 2007, Maine Yankee, Connecticut Yankee and Yankee Atomic filed additional claims against the DOE for unspecified damages incurred for periods subsequent to the original case discussed above. On July 1, 2009, in a notification to the DOE, Maine Yankee, Connecticut Yankee and Yankee Atomic filed their claimed costs for damages. Maine Yankee claimed $43 million since January 1, 2003 and Connecticut Yankee and Yankee Atomic claimed $135.4 million and $86.1 million, respectively since January 1, 2002. For all three companies the damages were claimed through December 31, 2008. A trial date has been set for the beginning of August 2011.

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

NOTE 5 - FINANCIAL INSTRUMENTS

The estimated fair value of financial instruments follows (dollars in thousands):

	March 31, 2011		December 31, 2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Power contract derivative assets	**$81**	**$81**	$28	$28
Long-term debt:				
First mortgage bonds (includes current portion)	**$167,500**	**$188,817**	$167,500	$188,467
Industrial/Economic Development bonds	**$40,800**	**$40,211**	$40,800	$40,521
Credit facility borrowings	**$0**	**$0**	$13,695	$13,695

At March 31, 2011, our power-related derivatives consisted of FTRs. There were no related unrealized gains or losses in 2011 or 2010. For a discussion of the valuation techniques used for power contract derivatives see Note 6 - Fair Value - Power-related Derivatives below.

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

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

NOTE 6 - FAIR VALUE

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

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

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

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

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

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

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

Level 1: Quoted prices (unadjusted) are available in active markets for identical assets or liabilities as of the reporting date. Level 1 includes cash equivalents that consist of money market funds and directly held securities in our non-qualified Millstone Decommissioning Trust Fund.

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

Level 3: Pricing inputs include significant inputs that are generally less observable. Unobservable inputs may be used to measure the asset or liability where observable inputs are not available. We develop these inputs based on the best information available, including our own data. Level 3 instruments include derivatives related to our forward energy purchases and sales, financial transmission rights and a power-related option contract. There were no changes to our Level 3 fair value measurement methodologies during 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 March 31, 2011			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities	**$1,680**	**$2,961**		**$4,641**
Marketable debt securities				
Corporate bonds		**345**		**345**
U.S. Government issued debt securities (Agency and Treasury)		**900**		**900**
State and municipal		**43**		**43**
Other		**27**		**27**
Total marketable debt securities		**1,315**		**1,315**
Cash equivalents and other		**50**		**50**
Total investments in securities	**1,680**	**4,326**		**6,006**
Restricted cash - long-term		**14,403**		**14,403**
Cash equivalents	**683**			**683**
Restricted cash		**2,093**		**2,093**
Power-related derivatives - current			**81**	**81**
Total assets	**$2,363**	**$20,822**	**$81**	**$23,266**

	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 funds have been obtained. Due to these observable inputs, fixed income, equity and cash equivalent securities in the qualified fund are classified as Level 2. Equity securities are held directly in our non-qualified trust and actively traded quoted prices for these securities have been obtained. Due to these observable inputs, these equity securities are classified as Level 1.

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

Cash Equivalents and Restricted Cash The market approach is used to measure the fair values of money market funds and other short-term investments included in cash equivalents and restricted cash. We have the ability to transact our money market funds at the net asset value price per share and can withdraw those funds without a penalty. We are able to obtain actively traded quoted prices for these funds; therefore they are classified as Level 1. We are able to obtain a quoted price for our 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 Condensed 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 March 31, 2011 and December 31, 2010, our derivatives consisted of FTRs. Our primary valuation technique to measure the fair value of these derivative assets and liabilities is the income approach, which involves determining a present value amount based on estimated future cash flows. However, when circumstances warrant, we may also use alternative approaches as described below to calculate the fair value for each type of derivative. Since many of the valuation inputs are not observable in the market, we have classified our derivative assets and liabilities as Level 3.

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

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

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

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

	Three months ended March 31	
	2011	**2010**
Balance as of January 1	**$28**	$254
Gains and losses (realized and unrealized)		
Included in earnings	**(7)**	1,650
Included in Regulatory and other assets/liabilities	**60**	5,365
Purchases, sales, issuances and net settlements	**0**	(1,683)
Balance at March 31	**$81**	$5,586

At March 31, 2011, 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 Condensed 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 minimal realized gains and 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 to our debt securities in the first quarter of 2011.

In 2010, we had a minimal amount of realized gains and realized losses. In 2010, there were no non-credit loss impairments and no permanent impairments or 'credit losses' associated with our debt securities in 2010.

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

	As of March 31, 2011			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Marketable equity securities	**$3,126**	**$1,515**		**$4,641**
Marketable debt securities				
Corporate bonds	**328**	**19**	**($2)**	**345**
U.S. Government issued debt securities (Agency and Treasury)	**857**	**46**	**(3)**	**900**
State and municipal	**42**	**1**		**43**
Other	**26**	**1**		**27**
Total marketable debt securities	**1,253**	**67**	**(5)**	**1,315**
Cash equivalents and other	**50**			**50**
Total	**$4,429**	**$1,582**	**($5)**	**$6,006**

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

Information related to the fair value of debt securities at March 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	$56	$307	$261	$691	$1,315

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

NOTE 8 – RESTRICTED CASH

At March 31, 2011, we had $16.5 million invested in a restricted cash account comprised of unreimbursed VEDA bond financing proceeds. The investments in this account consist primarily of commercial paper.

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

We recorded $2.1 million of the restricted cash as a current asset on the Condensed Consolidated Balance Sheet, which represents expenses paid that are expected to be reimbursed at the next requisition date. In the first quarter of 2011 we received reimbursements of $7 million. We expect to receive reimbursements of the remaining proceeds held in trust by early 2012.

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 adjustment to reflect changes in power supply and transmission-by-others costs and annual base rate adjustments to reflect changing costs; and an annual ESAM adjustment to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity is adjusted annually to reflect one-half of the change in the average yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The ESAM provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to customers in a future period. If the actual return on equity of our regulated business falls between 75 and 125 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and customers. Any earnings shortfall in excess of 125 basis points below the allowed return on equity is fully recovered from customers. As such, the minimum return for our regulated business is 100 basis points below the allowed return. These adjustments are made at the end of each fiscal year.

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

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

On September 3, 2010, the PSB approved the implementation of a new initiatives adder under our alternative regulation plan. In order to qualify for treatment as a new initiative the following criteria must be met: 1) the risk associated with implementing the new initiative is of a nature that is distinct from the ordinary business risk that we assume in discharging our public service obligation, and 2) the costs associated with implementing the new initiative are material. In our 2010 base rate filing we were allowed recovery of $0.2 million for a new initiative that does not meet the PSB criteria. This amount is being returned to customers in 2011.

Using the methodology specified in our alternative regulation plan, our 2010 return on equity from the regulated portion of our business was 8.95 percent. We filed this calculation with the PSB in April 2011. No ESAM adjustment was required since this return was within 75 basis points of our 2010 allowed return on equity of 9.59 percent.

In 2010, under the exogenous effects provision of the ESAM, we deferred $4.2 million of costs related to three major storms and tax law changes. On January 31, 2011 we filed with the PSB for recovery of these costs through the ESAM over a 12-month period commencing on July 1, 2011. On February 24, 2011, we filed a request with the PSB to offset the $4.2 million 2010 ESAM deferral against the fourth quarter 2010 PCAM over-collection. Although the PSB has not yet acted on the ESAM filing, on March 29, 2011 they allowed us to offset this deferral against the 2010 fourth quarter PCAM adjustment discussed below. Should the final ESAM amount approved be different than the amount requested, the difference will be included in a future PCAM adjustment.

The PCAM adjustments for 2010 were calculated to be an over-collection of $0.5 million in the first quarter, an under-collection of $1 million in the second quarter and over-collections of less than $0.1 million in the third quarter and $5.2 million in the fourth quarter. The over-collection in the first quarter was recorded as current liability and returned to customers over the three months ended September 30, 2010. The under-collection in the second quarter was recorded as a current asset and recovered from customers over the three months ended December 31, 2010. The over-collection in the third quarter was recorded as current liability and was returned to customers over the three months ended March 31, 2011. The fourth quarter PCAM over-collection was recorded as a current liability. As discussed above, we received approval to offset this against the 2010 ESAM and the net amount of $1 million will be returned to customers over the three months ending June 30, 2011. We filed PCAM reports, including supporting documentation, each quarter with the PSB identifying the over- and under-collections. In each case, the DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing.

The PCAM adjustment for the first quarter of 2011 was an over-collection of $1 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending September 30, 2011. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

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

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

To address these concerns, on July 6, 2010 we petitioned the PSB to approve changes to the current plan to: a) extend its duration; b) alter the methodology for implementing the non-power cost cap; and c) reset the allowed ROE as noted above to 10.22 percent

On December 21, 2010, we filed the ARP MOU between us and the DPS with the PSB regarding certain amendments to the alternative regulation plan including the ROE provisions. Under the ARP MOU, the term of the alternative regulation plan would be extended through 2013 and the allowed ROE would be set at 9.59 percent for 2011. In addition, the ARP MOU provided for a modification to the alternative regulation plan to include a benchmarking mechanism that affects the non-power cost cap for rate years 2012 and 2013. There was also a provision to adjust the non-power cost cap for any cost of service change resulting from an ROE change. As part of the settlement, an agreement was also reached with respect to our 2011 base rate filing.

On December 29, 2010, the PSB issued an order allowing us to implement a 7.46 percent increase in retail rates, reflecting an allowed ROE of 9.18 percent, effective with bills rendered January 1, 2011. The PSB concluded that there was not sufficient time to conduct a meaningful assessment of the issues raised by the ARP MOU, particularly given the absence of pre-filed supporting testimony. The PSB opened an investigation into our existing rates to assess whether further adjustment is necessary pending its review of the ARP MOU.

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 the ARP MOU that was filed with the PSB on December 21, 2010, except that the PSB granted us an allowed ROE for 2011 of 9.45 percent, rather than the 9.59 percent contained in the ARP MOU.

On April 6, 2011 the PSB convened a prehearing conference in connection with the investigation into our existing rates. We reported that, because of offsetting factors, the amendment to our alternative regulation plan approved by PSB order on March 31, 2011 would not result in a change to the 7.46 percent rate increase implemented on January 1, 2011. The PSB agreed to close the rate investigation pending submission of compliance cost of service and rate base updates for recognition under the 2011 base rates utilized within the amended and restated alternative regulation plan in effect for 2011. We submitted the compliance cost of service and rate base updates on April 20, 2011. On April 26, 2011 the PSB issued an order approving the compliance cost of service and closing the 2011 rate investigation, thereby leaving intact the 7.46 percent increase effective January 1, 2011.

Staffing Level Investigation On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS.

On November 30, 2009, we filed the Staffing MOU with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our staffing levels. Under the Staffing MOU, in lieu of retaining a management consultant to perform a comprehensive review of our organizational structure and staffing, we and the DPS have agreed that we will reduce our staffing levels over a five-year period by a total of 17 positions as compared to the 549 positions we had on January 1, 2009. This reduction shall be in addition to the staffing reductions contemplated by the implementation of CVPS SmartPower®. We retain discretion in how to achieve the staffing reductions, and the DPS has agreed that it shall not oppose the recovery in rates of all reasonable costs associated with staffing and related compensation during the term of the Staffing MOU, provided that recovery of such costs is otherwise consistent with normal ratemaking standards. By December 31, 2010 we had reduced staffing levels to 517 employees. Nothing in the Staffing MOU precludes us from seeking to add staff as reasonably necessary in response to new requirements imposed by the state or federal government.

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

CVPS SmartPower® On October 27, 2009, the DOE announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation. As a participant on Vermont's smart grid stimulus application, we expect to receive a grant of over $31 million.

On April 15, 2010, we signed an agreement with the DOE for our portion of the Smart Grid stimulus grant and project and the agreement became effective April 19, 2010. The agreement includes provisions for funding and other requirements. We are eligible to receive reimbursement of 50 percent of our total project costs incurred since August 6, 2009, up to $31 million. From the inception of the project through March 31, 2011, we have incurred $5.3 million of costs, of which $2.9 million were operating expenses and $2.4 million were capital expenditures. We have submitted requests for reimbursement of $2.5 million and have received $2.4 million to date.

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

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

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the DOE under the ARRA; however, 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.

Regulatory Accounting Under FASB's guidance for regulated operations, we account for certain transactions in accordance with permitted regulatory treatment whereby regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered through future revenues. In the event that we no longer meet the criteria under accounting for regulated operations and there is not a rate mechanism to recover these costs, we would be required to write off $12.1 million of regulatory assets (total regulatory assets of $39.7 million less pension and postretirement medical costs of $27.6 million), $0.5 million of other deferred charges - regulatory and $5.1 million of other deferred credits - regulatory. This would result in a total charge to operations of $7.5 million on a pre-tax basis as of March 31, 2011. We would be required to record pre-tax pension and postretirement costs of $27.2 million to Accumulated Other Comprehensive Loss and $0.4 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).

	March 31, 2011	December 31, 2010
Regulatory assets		
Pension and postretirement medical costs	**$27,553**	$27,959
Nuclear plant dismantling costs	**6,466**	6,821
Nuclear refueling outage costs - Millstone Unit #3	**324**	486
Income taxes	**4,541**	4,480
Asset retirement obligations and other	**830**	730
Total Regulatory assets	**39,714**	40,476
Less: Current portion	**2,281**	1,924
Total Regulatory assets less current portion	**$37,433**	$38,552
Other deferred charges - regulatory		
ESAM deferred costs	**$0**	$4,157
Environmental	**452**	0
Other	**5**	181
Total Other deferred charges - regulatory	**457**	4,338
Less: Current portion	**0**	2,078
Total Other deferred charges - regulatory less current portion	**$457**	$2,260
Other deferred credits - regulatory		
Asset retirement obligation - Millstone Unit #3	**$3,233**	$3,009
Vermont Yankee settlements	**55**	0
Unrealized gains on power-related derivatives	**60**	0
CVPS SmartPower® grant reimbursements	**941**	1,180
Other	**824**	805
Total Other deferred credits - regulatory	**5,113**	4,994
Less: Current Portion	**1,086**	1,108
Total Other deferred credits - regulatory less current portion	**$4,027**	$3,886

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

Regulatory assets for pension and postretirement medical costs are discussed in Note 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 - POWER-RELATED DERIVATIVES

We are exposed to certain risks in managing our power supply resources to serve our customers, and we use derivative financial instruments to manage those risks. The primary risk managed by using derivative financial instruments is commodity price risk. Currently, our power supply forecast shows energy purchase and production amounts in excess of our load requirements through 2011. Because of this projected power surplus, we entered into one forward power sale contract for 2011. This forward sale was initially structured as a physical sale of excess power. In January 2011 the sale contract was renegotiated as a rate swap that settles financially. We have concluded that neither the original physical sale nor the subsequent rate swap contract is a derivative, since a notional amount does not exist under the terms of either contract.

On occasion, we will forecast a temporary power supply shortage such as when Vermont Yankee becomes unavailable. We typically enter into short-term forward power purchase contracts to cover a portion of these expected power supply shortages, which helps to reduce price volatility in our net power costs. We have not yet entered into a forward purchase contract for the 2011 Vermont Yankee refueling outage. Our power supply forecast shows that in 2012, our load requirements will exceed our energy purchase and production amounts, as certain committed long-term power purchase contracts begin to expire.

On August 12, 2010, we executed a significant long-term power purchase contract with HQUS and we have concluded that this contract meets the "normal purchase, normal sale" exception to derivatives accounting; therefore, we are not required to calculate the fair value of this contract. For additional information on this contract, see Note 13 - Commitments and Contingencies - New Hydro-Québec Agreement.

Several years ago, we entered into the Hydro-Québec Sellback #3 contract, a long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice. The option under this contract expired on December 31, 2010. In addition, we are able to economically hedge our exposure to congestion charges that result from constraints on the transmission system with FTRs. FTRs are awarded to the successful bidders in periodic auctions administered by ISO-NE. We do not use derivative financial instruments for trading or other purposes.

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

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

	MWh (000s)	
	2011	**2010**
Commodity		
Forward Energy Contracts	0	368.2
Financial Transmission Rights	1,480.5	1,559.3
Hydro-Quebec Sellback #3	0	136.9

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

	2011	2010
Net realized gains (losses) reported in operating revenues	**$0**	$1,672
Net realized gains (losses) reported in purchased power	**(7)**	(22)
Net realized gains (losses) reported in earnings	**($7)**	$1,650

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 Condensed Consolidated Statements of Cash Flows. For information on the location and amounts of derivative fair values on the Condensed Consolidated Balance Sheets see Note 6 - Fair Value.

Certain of our power-related derivative instruments contain provisions for performance assurance that may include the posting of collateral in the form of cash or letters of credit, or other credit enhancements. Our counterparties will typically establish collateral thresholds that represent credit limits, and these credit limits vary depending on our credit rating. If our current credit rating were to decline, certain counterparties could request immediate payment and full, overnight ongoing collateralization on derivative instruments in net liability positions. We have no derivative instruments with credit-risk-related contingent features that were in a liability position on March 31, 2011 or December 31, 2010. For information concerning performance assurance, see Note 13 - Commitments and Contingencies - Performance Assurance.

NOTE 11 – NOTES PAYABLE

Credit Facility: We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated November 3, 2008 that expires on November 2, 2011. The Credit Agreement contains financial and non-financial covenants. Our obligation under the Credit Agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. At December 31, 2010, $13.7 million in loans and $5.5 million in letters of credit were outstanding under this credit facility. At March 31, 2011, $5.5 million in letters of credit were outstanding under this credit facility. We had periodic borrowings under this facility during the first quarter of 2011, but there were no loans outstanding at March 31, 2011. In 2011 we intend to renew or replace this facility.

NOTE 12 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

The fair value of Pension Plan trust assets was $108.2 million at March 31, 2011 and $107.4 million at December 31, 2010. The unfunded accrued pension benefit obligation recorded on the Condensed Consolidated Balance Sheets was $22 million at March 31, 2011 and $21.1 million at December 31, 2010.

The fair value of Postretirement Plan trust assets was $19.1 million at March 31, 2011 and $18.4 million at December 31, 2010. The unfunded accrued postretirement benefit obligation recorded on the Condensed Consolidated Balance Sheets was $7.1 million at March 31, 2011, and $6.8 million at December 31, 2010.

Components of net periodic benefit costs follow (dollars in thousands):

	Pension Benefits		**Postretirement Benefits**	
	2011	2010	**2011**	2010
Service cost	**$1,142**	$1,026	**$198**	$228
Interest cost	**1,851**	1,754	**330**	395
Expected return on plan assets	**(2,120)**	(2,063)	**(357)**	(301)
Amortization of transition obligation	**0**	0	**64**	64
Amortization of prior service cost	**104**	107	**70**	70
Amortization of net actuarial loss	**60**	0	**51**	242
Net periodic benefit cost	**1,037**	824	**356**	698
Less amounts capitalized	**212**	89	**73**	76
Net benefit costs expensed	**$825**	$735	**$283**	$622

Investment Strategy Our pension investment policy seeks to achieve sufficient growth to enable the Pension Plan to meet our future benefit obligations to participants, maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 54 percent of plan assets be invested in equity securities and 46 percent of plan assets be invested in debt securities. The debt securities are primarily comprised of long-duration bonds to match changes in plan liabilities.

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

Trust Fund Contributions: In April 2011, we contributed $4.1 million to the pension trust fund. We expect to contribute $1.5 million to the postretirement medical fund later in 2011. In July 2010, we contributed $3.3 million to the pension trust fund and $2.7 million to the postretirement medical trust fund.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

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

Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. We purchase replacement energy as needed when the Vermont Yankee plant is not operating or is operating at reduced levels. We typically acquire most of this replacement energy through forward purchase contracts and account for those contracts as derivatives. Our total VYNPC purchases were $17.1 million for the three months ended March 31, 2011 and $16.2 million for the three months ended March 31, 2010.

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

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

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

Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that we could lose this resource if the plant shuts down for any reason before that date, and its future beyond that date is uncertain. An early shutdown could cause our customers to lose the economic benefit of an energy volume of close to 50 percent of our total committed supply and we would have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. While this has been a significant concern in the past, the ever-shortening 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 capacity, and due to significant reductions in natural gas prices, electrical energy is available at competitive rates. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of any costs related to such shutdown.

Under Vermont law, in addition to a favorable Vermont legislative vote, the PSB must issue a Certificate of Public Good in order for the plant to continue to operate 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. The new Vermont Legislature elected on November 2, 2010 could vote differently, although the political makeup of the House and Senate remains largely unchanged and there is nothing to suggest that a new vote will be held. Also, Vermont elected a new governor who advocated as a member of the Vermont Senate and during the gubernatorial campaign that the Vermont Yankee plant should close when its current license expires, and he maintains that position.

After the November election, Entergy announced it had begun pursuing a possible sale of the plant, apparently concluding that the plant had a better chance at remaining part of Vermont's power supply under new ownership. We vigorously engaged in contract talks with Entergy-Vermont Yankee for the specific purpose of increasing the chances the plant would continue to operate beyond 2012. On March 29, 2011, Entergy announced its sale process had concluded unsuccessfully. Consequently, the potential for state legislative and regulatory approval of continued plant operations is now, in our view, less likely. However, as discussed more fully below, Entergy-Vermont Yankee is seeking to operate the plant beyond March 21, 2012, without such approvals.

On March 10, 2011, the NRC voted 4-0 to approve the 20-year license extension through March 21, 2032 requested by Entergy-Vermont Yankee. This approval removes the last federal-level regulatory requirement for relicensing of the Vermont Yankee station.

Entergy-Vermont Yankee, previously attempting to overcome legislative concerns, recently challenged the state's authority as it relates to relicensing. In a federal lawsuit filed on April 18, 2011, Entergy-Vermont Yankee contended that the state was improperly attempting to interfere with its relicensing. In the complaint filed in U.S. District Court for the District of Vermont, Entergy-Vermont Yankee is seeking 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 seeks both declaratory and injunctive relief, and contends that Vermont's attempts to shutter the plant are preempted by the Atomic Energy Act, the Federal Power Act and the Commerce Clause of the U.S. Constitution. The state of Vermont has vowed to vigorously defend its position. The federal court has scheduled a pretrial status conference for May 5, 2011, during which time procedural matters will be discussed including the litigation schedule. We are evaluating the potential impact of the litigation on our financial statements and on our customers. The outcome of this matter is uncertain at this time.

Hydro-Québec: We are purchasing power from Hydro-Québec under the VJO power contract. The VJO power contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between us and Hydro-Québec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO power contract runs through 2020, but our purchases under the contract end in 2016. The average level of deliveries under the current contract decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015. Our total purchases under the VJO Power contract were $16.5 million for the three months ended March 31, 2011 and $16.6 million for the three months ended March 31, 2010

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

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

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

There are specific contractual provisions providing that in the event any VJO member fails to meet its obligation under the contract with Hydro-Québec, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. As of March 31, 2011, our obligation is about 47 percent of the total VJO power contract through 2016, and represents approximately $269.1 million, on a nominal basis.

In accordance with FASB's guidance for guarantees, we are required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. With regard to the "step-up" provision in the VJO power contract, we must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. We believe this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power 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 $316 million for the remainder of the contract, assuming that all members of the VJO defaulted by April 1, 2011 and remained in default for the duration of the contract. In such a scenario, we would then own the power and could seek to recover our costs from the defaulting members or our retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

Independent Power Producers: We receive power from several Independent IPPs. These plants use water or biomass as fuel. Most of the power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Our total purchases from IPPs were $6.3 million for March 31, 2011 and March 31, 2010.

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.

DOE Litigation 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 has 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 is 45 days.

We continue to pay our share of the DOE Spent Fuel assessment expenses levied on actual generation and will share in recovery from the lawsuit, if any, in proportion to our ownership interest. We expect that our share of a recovery, if any, would be credited to our retail customers.

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

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

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

The obligations of HQUS and each Buyer are contingent upon the receipt of certain governmental approvals. On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. 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, which we plan to execute as proposed. In the event the HQUS PPA is terminated with respect to any Buyer as a result of such Buyer's failure to receive governmental approvals, each of the other Buyers will have an option to purchase the additional energy.

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

Performance Assurance We are subject to performance assurance requirements through ISO-NE under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $3.2 million with ISO-NE. We are required to post collateral for all net 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 March 31, 2011, we had posted $5.6 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 $0.1 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.

The total reserve for environmental matters was $0.8 million as of March 31, 2011 and $0.8 million as of December 31, 2010. The reserve for environmental matters is included as current and long-term liabilities on the Condensed 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, which represented Vermont's hazardous waste tax on contaminated soil that has been removed from the site. Some additional sitework including grading and vegetation planting will occur in 2011. In February 2011, we submitted a Construction Completion Report for the project to the EPA and VANR for review. The report documented remedial construction and confirmatory sampling activities. As of March 31, 2011, our estimate of the remaining obligation is less than $0.1 million.

Brattleboro Manufactured Gas Facility: In the 1940s, we owned and operated a manufactured gas facility in Brattleboro, Vermont. We ordered a site assessment in 1999 at the request of the State of New Hampshire. In 2001, New Hampshire indicated that no further action was required, although it reserved the right to require further investigation or remedial measures. In 2002, the VANR notified us that our corrective action plan for the site was approved. As of March 31, 2011, our estimate of the remaining obligation is $0.5 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.

We are actively discussing the proposed redevelopment with consultants for the Town of Brattleboro and the Windham Regional Commission. We have indicated to the consultants our willingness to partner with the Town of Brattleboro through a formal remediation agreement to participate in the redevelopment. This participation will assure continued acknowledgement of site contamination. We received a non-binding letter from the Town of Brattleboro summarizing its preferred remedial plan.

We have requested that the Town of Brattleboro schedule a meeting with all interested parties to discuss the remediation of the gas plant site and overall waterfront properties. We expect that this meeting will occur in the second quarter of 2011. Subsequently, we will reassess its probabilistic cost estimate to remediate the site.

Dover, New Hampshire, Manufactured Gas Facility: In 1999, PSNH contacted us about this site. PSNH alleged that we were partially liable for cleanup, since the site was previously operated by Twin State Gas and Electric, which merged into CVPS on the same day that PSNH bought the facility. In 2002, we reached a settlement with PSNH in which certain liabilities we might have had were assigned to PSNH in return for a cash settlement we paid based on completion of PSNH's cleanup effort. As of March 31, 2011, our estimate of the remaining obligation was less than $0.1 million.

Middlebury Lower Substation: By letter dated February 5, 2010, the VANR Sites Management Section informed us they require additional investigation of the soil contamination at the Middlebury Lower Substation. This was a result of voluntarily submitted information from an internal soil sampling that we completed in the fall of 2009. The soil sampling showed elevated levels of TPH, which will require remediation. Some soil removal has already occurred and the remaining contaminated material will be removed in conjunction with the substation reconstruction. As of March 31, 2011, our estimate of the remaining obligation was $0.1 million.

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 at portions at the site. We submitted a letter to the VANR Sites Management Section proposing that PCB remediation efforts would be sufficient mitigation for TPH and pesticide contamination, and proposed to collect soil samples for confirmatory testing of these compounds. Remediation is expected to begin during the third quarter of 2011. As of March 31, 2011, our estimate of the remaining obligation was $0.2 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 *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 March 31, 2011 is approximately \$0.4 million. The total future minimum lease payments required for all lease schedules under this agreement at March 31, 2011 is \$3.3 million. As of March 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 March 31, 2011 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 March 31, 2011 is \$2.1 million. As of March 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 March 31, 2011 was \$2.9 million.

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

NOTE 14 – PENDING ACQUISITIONS

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

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

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

On February 25, 2011, we filed an MOU between us, the DPS, the Town of Proctor and Omya, with the PSB that resolves all the outstanding issues between the parties concerning our acquisition of Vermont Marble. As part of the settlement, we will pay $28.3 million for the generating assets and approximately $1 million for the transmission and distribution assets. We will be allowed recovery from customers of $27 million for the generating assets and the $1 million for the transmission and distribution assets. Included in the MOU is the creation of a value sharing mechanism that provides for certain excess value received by us to be split between our customers, Omya and our shareholders if energy market prices and hydro improvements yield more value than anticipated. This will provide us with an opportunity to recover the $1.3 million not otherwise recovered in rates.

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.

On March 4, 2011 we signed an amended and restated purchase and sale agreement with Omya, Inc. to incorporate the terms of the MOU filed on February 25, 2011. The PSB held a hearing on the matter on April 11, 2011 and we expect a ruling on the petition for approval of the transaction in the second quarter of 2011.

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

NOTE 15- SEGMENT REPORTING

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

The accounting policies of operating segments are the same as those described in Note 2 - Summary of Significant Accounting Policies. All segment operations are managed centrally by CV - VT. Segment profit or loss is based on profit or loss from continuing operations after income taxes and preferred stock dividends. Other Companies are below the quantitative thresholds individually and in the aggregate.

Inter-segment revenues were a nominal amount in all periods presented. The following table provides segment financial data for the period ended December 31 (dollars in thousands):

	CV-VT	Unregulated Companies	Reclassification & Consolidating Entries	Consolidated
March 31, 2011				
Revenues from external customers	**$97,085**	**$423**	**($423)**	**$97,085**
Net income	**$8,358**	**$67**		**$8,425**
Total assets at March 31, 2011	**$697,188**	**$3,062**	**($234)**	**$700,016**
March 31, 2010				
Revenues from external customers	$91,007	$433	($433)	$91,007
Net income	$4,149	$53		$4,202
Total assets at December 31, 2010	$707,973	$3,019	($246)	$710,746

Item 2. 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 Condensed Consolidated Financial Statements. The discussion below also includes non-U.S. GAAP measures referencing earnings per diluted share for variances described below in Results of Operations. We use this measure to provide additional information and believe that this measurement is useful to investors to evaluate the actual performance and contribution of our business activities. This non-U.S. GAAP measure should not be considered as an alternative to our consolidated fully diluted EPS determined in accordance with U.S. GAAP as an indicator of our operating performance.

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

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

We cannot predict the outcome of any of these matters; accordingly, there can be no assurance as to actual results. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise. A more detailed assessment of the risks that could cause actual results to materially differ from current expectations is in Part I, Item 1A, Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2010.

EXECUTIVE SUMMARY

Our consolidated earnings for the first three months of 2011 were $8.4 million, or 62 cents per diluted share of common stock. This compares to consolidated earnings of $4.2 million, or 35 cents per diluted share of common stock for the first three months of 2010. The primary drivers of the year-over-year earnings variances are described in Results of Operations below.

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

We discuss these financial initiatives and the risks facing our business in more detail below.

RETAIL RATES AND ALTERNATIVE REGULATION

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

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

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

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

On September 3, 2010, the PSB approved the implementation of a new initiatives adder under our alternative regulation plan. In order to qualify for treatment as a new initiative the following criteria must be met: 1) the risk associated with implementing the new initiative is of a nature that is distinct from the ordinary business risk that we assume in discharging our public service obligation, and 2) the costs associated with implementing the new initiative are material. In our 2010 base rate filing we were allowed recovery of $0.2 million for a new initiative that does not meet the PSB criteria. This amount is being returned to customers in 2011.

Using the methodology specified in our alternative regulation plan, our 2010 return on equity from the regulated portion of our business was 8.95 percent. We filed this calculation with the PSB in April 2011. No ESAM adjustment was required since this return was within 75 basis points of our 2010 allowed return on equity of 9.59 percent.

In 2010, under the exogenous effects provision of the ESAM, we deferred $4.2 million of costs related to three major storms and tax law changes. On January 31, 2011 we filed with the PSB for recovery of these costs through the ESAM over a 12-month period commencing on July 1, 2011. On February 24, 2011, we filed a request with the PSB to offset the $4.2 million 2010 ESAM deferral against the fourth quarter 2010 PCAM over-collection. Although the PSB has not yet acted on the ESAM filing, on March 29, 2011 they allowed us to offset this deferral against the 2010 fourth quarter PCAM adjustment discussed below. Should the final ESAM amount approved be different than the amount requested, the difference will be included in a future PCAM adjustment.

The PCAM adjustments for 2010 were calculated to be an over-collection of $0.5 million in the first quarter, an under-collection of $1 million in the second quarter and over-collections of less than $0.1 million in the third quarter and $5.2 million in the fourth quarter. The over-collection in the first quarter was recorded as current liability and returned to customers over the three months ended September 30, 2010. The under-collection in the second quarter was recorded as a current asset and recovered from customers over the three months ended December 31, 2010. The over-collection in the third quarter was recorded as current liability and was returned to customers over the three months ended March 31, 2011. The fourth quarter PCAM over-collection was recorded as a current liability. As discussed above, we received approval to offset this against the 2010 ESAM and the net amount of $1 million will be returned to customers over the three months ending June 30, 2011. We filed PCAM reports, including supporting documentation, each quarter with the PSB identifying the over- and under-collections. In each case, the DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing.

The PCAM adjustment for the first quarter of 2011 was an over-collection of $1 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending September 30, 2011. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

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

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

To address these concerns, on July 6, 2010 we petitioned the PSB to approve changes to the current plan to: a) extend its duration; b) alter the methodology for implementing the non-power cost cap; and c) reset the allowed ROE as noted above to 10.22 percent

On December 21, 2010, we filed the ARP MOU between us and the DPS with the PSB regarding certain amendments to the alternative regulation plan including the ROE provisions. Under the ARP MOU, the term of the alternative regulation plan would be extended through 2013 and the allowed ROE would be set at 9.59 percent for 2011. In addition, the ARP MOU provided for a modification to the alternative regulation plan to include a benchmarking mechanism that affects the non-power cost cap for rate years 2012 and 2013. There was also a provision to adjust the non-power cost cap for any cost of service change resulting from an ROE change. As part of the settlement, an agreement was also reached with respect to our 2011 base rate filing.

On December 29, 2010, the PSB issued an order allowing us to implement a 7.46 percent increase in retail rates, reflecting an allowed ROE of 9.18 percent, effective with bills rendered January 1, 2011. The PSB concluded that there was not sufficient time to conduct a meaningful assessment of the issues raised by the ARP MOU, particularly given the absence of pre-filed supporting testimony. The PSB opened an investigation into our existing rates to assess whether further adjustment is necessary pending its review of the ARP MOU.

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 the ARP MOU that was filed with the PSB on December 21, 2010, except that the PSB granted us an allowed ROE for 2011 of 9.45 percent, rather than the 9.59 percent contained in the ARP MOU.

On April 6, 2011 the PSB convened a prehearing conference in connection with the investigation into our existing rates. We reported that, because of offsetting matters, the amendment to our alternative regulation plan approved by PSB order on March 31, 2011 would not result in a change to the 7.46 percent rate increase implemented on January 1, 2011. The PSB agreed to close the rate investigation pending submission of compliance cost of service and rate base updates for recognition under the 2011 base rates utilized within the amended and restated alternative regulation plan in effect for 2011. We submitted the compliance cost of service and rate base updates on April 20, 2011. On April 26, 2011 the PSB issued an order approving the compliance cost of service and closing the 2011 rate investigation, thereby leaving intact the 7.46 percent increase effective January 1, 2011.

Staffing Level Investigation On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS.

On November 30, 2009, we filed the Staffing MOU with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our staffing levels. Under the Staffing MOU, in lieu of retaining a management consultant to perform a comprehensive review of our organizational structure and staffing, we and the DPS have agreed that we will reduce our staffing levels over a five-year period by a total of 17 positions as compared to the 549 positions we had on January 1, 2009. This reduction shall be in addition to the staffing reductions contemplated by the implementation of CVPS SmartPower®. We retain discretion in how to achieve the staffing reductions, and the DPS has agreed that it shall not oppose the recovery in rates of all reasonable costs associated with staffing and related compensation during the term of the Staffing MOU, provided that recovery of such costs is otherwise consistent with normal ratemaking standards. By December 31, 2010 we had reduced staffing levels to 517 employees. Nothing in the Staffing MOU precludes us from seeking to add staff as reasonably necessary in response to new requirements imposed by the state or federal government.

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

CVPS SmartPower® On October 27, 2009, the DOE announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation. As a participant on Vermont's smart grid stimulus application, we expect to receive a grant of over $31 million.

On April 15, 2010, we signed an agreement with the DOE for our portion of the Smart Grid stimulus grant and project and the agreement became effective April 19, 2010. The agreement includes provisions for funding and other requirements. We are eligible to receive reimbursement of 50 percent of our total project costs incurred since August 6, 2009, up to $31 million. From the inception of the project through March 31, 2011, we have incurred $5.3 million of costs, of which $2.9 million were operating expenses and $2.4 million were capital expenditures. We have submitted requests for reimbursement of $2.5 million and have received $2.4 million to date.

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

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

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the DOE under the ARRA; however, 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.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Cash Flows At March 31, 2011, we had cash and cash equivalents of $15.1 million compared to $5.1 million at March 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 and borrowings under our revolving credit facility. Our primary uses of cash in 2011 included capital expenditures, common and preferred dividend payments, repayments of borrowings under our revolving credit facility and working capital needs.

Operating Activities: Operating activities provided $32.4 million in 2011, compared to $24.9 million in 2010. The increase of $7.4 million was primarily due to: $5.8 million from our 7.46 percent rate increase effective January 1, 2011, a $2.7 million increase in net income tax refunds, a $0.9 million increase in distributions received from affiliates, a $1.1 million recovery of bad debt expense, and a $2.3 million increase in working capital and other operating activities, partially offset by a $5.4 million decrease in special deposits and restricted cash for power collateral.

At March 31, 2011, our retail customers' accounts receivable over 60 days totaled $2.8 million compared to $2.6 million at December 31, 2010, which was an increase of 7.8 percent.

Investing Activities: Investing activities used $2.8 million in 2011, compared to $6 million in 2010. The decrease of $3.2 million is due to: $7 million of reimbursements of restricted cash related to capital project fund investments, partially offset by an increase of $4.2 million for construction and plant expenditures, and a $0.4 million increase in project reimbursements from the DOE. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements.

Financing Activities: Financing activities used $17.1 million in 2011, compared to $15.9 million in 2010. The increase of $1.2 million is due to: a $0.4 million increase in common stock dividends paid, a $0.3 million increase in net credit facility repayments, a $0.1 million increase in other financing activities, and a $0.4 million decrease in net proceeds from the issuance of common stock.

Transco Based on current projections, Transco expects to need additional equity capital from 2011 through 2014, but its projections are subject to change based on a number of factors, including revised construction estimates, timing of project approvals from regulators, and desired changes in its equity-to-debt ratio. While we have no obligation to make additional investments in Transco, which are subject to available capital and appropriate regulatory approvals, we continue to evaluate investment opportunities on a case-by-case basis. We are currently considering additional investments of approximately $11.6 million in 2011, $32.6 million in 2012, $0 in 2013 and $28 million in 2014, but the timing and amounts depend on the factors discussed above and the amounts invested by other owners.

We are currently evaluating debt and equity issuance alternatives to fund these investments, but any investments that we make in Transco are voluntary, and subject to available capital and appropriate regulatory approvals. These capital investments in Transco and our core business provide value to customers and shareholders alike. They provide shareholders with a return on investment while helping to maintain and improve reliability for our customers.

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

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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.

On March 4, 2011 we signed an amended and restated purchase and sale agreement with Omya, Inc. to incorporate the terms of the MOU filed on February 25, 2011. The PSB held a hearing on the matter on April 11, 2011 and we expect a ruling on the petition for approval of the transaction in the second quarter of 2011.

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

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

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 Vermont Yankee plant outage or similar event could significantly impact our liquidity due to the potentially high cost of replacement power and performance assurance requirements arising from purchases through ISO-NE or third parties. An extended unplanned Vermont Yankee plant outage could involve cost recovery under the PCAM but in general would not be expected to materially impact our financial results, if the costs are recovered in retail rates in a timely fashion.

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

Global Economic Conditions We expect to have access to liquidity in the capital markets when needed at reasonable rates. We have access to a $40 million unsecured revolving credit facility and a $15 million unsecured revolving credit facility with two different lending institutions. However, sustained turbulence in the global credit markets could limit or delay our access to capital. As part of our enterprise risk management program, we routinely monitor our risks by reviewing our investments in and exposure to various firms and financial institutions.

Financing *Credit Facility:* We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated November 3, 2008 that expires on November 2, 2011. The Credit Agreement contains financial and non-financial covenants. Our obligation under the Credit Agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. At March 31, 2011, there were no loans and $5.5 million in letters of credit outstanding under this credit facility. We had periodic borrowings under this facility during the first three months of March 2011. In 2011 we intend to renew or replace this facility.

We also have a three-year, $15 million unsecured revolving credit facility with a different lending institution pursuant to a Credit Agreement dated December 22, 2010 that expires in December 2013. This facility replaced a 364-day, $15 million unsecured revolving credit facility that matured on December 29, 2010. The purpose and obligation under this credit agreement are the same as described above. At March 31, 2011, there were no loans or letters of credit outstanding under this credit facility. We have not used this facility for borrowings or letters of credit during the first three months of March 2011.

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

Covenants: Our long-term debt indentures, letters of credit, credit facilities and articles of association contain financial covenants. The most restrictive financial covenants include maximum debt to total capitalization of 65 percent, and minimum mortgage bond interest coverage of 2.0 times. At March 31, 2011, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit, credit facilities and material agreements.

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system. As of March 31, 2011, capital expenditures were $10 million.

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

Contractual Obligations *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 2-year period and will seek reimbursement from the DOE for approximately 50 percent of eligible project costs under the eEnergy Vermont SmartGrid Investment Grant.

Future Liquidity Needs In order to meet our expected levels of capital expenditures and investments in affiliates; we expect to need outside capital in the form of debt or equity over the next few years.

Performance Assurance We are subject to performance assurance requirements through ISO-NE under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $3.2 million with ISO-NE. We are required to post collateral for all net 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 March 31, 2010, we had posted $5.6 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 $0.1 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 financing arrangements, such as securitization of receivables, nor 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 $5.5 million letter of credit related to 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. Until the third quarter of 2010, we leased most vehicles and related equipment under operating lease agreements. These operating lease agreements are described in Note 13 - Commitments and Contingencies.

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

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

We are subject to extensive federal, state and local environmental regulations that monitor, among other things, emission allowances, pollution controls, maintenance and upgrading of facilities, site remediation, equipment upgrades and management of hazardous waste. We believe that we are materially in compliance with all applicable environmental and safety laws and regulations; however, there can be no assurance that we will not incur significant costs and liabilities in the future. See Note 13 – 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.

OTHER BUSINESS RISKS

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

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

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

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

Power Supply Risk: Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that the plant could be shut down earlier than expected if Entergy-Vermont Yankee determines that it is not economical to continue operating the plant, or due to environmental concerns. While this has been a significant concern in the past, the ever-shortening span of time before the contract's end and changes in the regional power market have decreased any risk the company might face. The New England Market currently has a significant surplus of available energy, 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, but the average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015. In August 2010, we signed a new contract for ongoing Hydro-Québec supplies 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: Our material power supply contracts are with Hydro-Québec and VYNPC. These contracts comprise the majority of our total annual MWh purchases. If one or both of these sources becomes unavailable for a period of time, there could be exposure to high wholesale power prices and that amount could be material.

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

Market Risk: See Item 3 - Quantitative and Qualitative Disclosures About Market Risk.

RESULTS OF OPERATIONS

The following is a detailed discussion of the results of operations for the first quarter of 2011. This should be read in conjunction with the Condensed Consolidated Financial Statements and accompanying notes included in this report.

Earnings for the three months ended March 31, 2011 increased $4.2 million, or 27 cents per diluted share of common stock compared to the same period in 2010. The table that follows provides a reconciliation of the primary year-over-year variances in diluted EPS for the three months ended March 31, 2011 versus 2010. The earnings per diluted share for each variance shown below are non-GAAP measures:

Reconciliation of Earnings Per Diluted Share

	2011 vs. 2010
2010 Earnings per diluted share	**$0.35**
Major Income Statement Variances:	
Higher operating revenue	0.30
Lower service restoration expenses	0.09
Higher equity in earnings of affiliates	0.07
Lower purchased power expense	0.02
Higher regulatory amortizations	(0.14)
Higher transmission expenses	(0.04)
Other (includes income tax adjustments, impact of additional common shares and various items)	(0.03)
2011 Earnings per diluted share	**$0.62**

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 for the three months ended March 31 are summarized below.

	Three months ended March 31			
	Revenues (in thousands)		MWh Sales	
	2011	2010	2011	2010
Residential	**$43,803**	$39,636	**281,030**	270,425
Commercial	**28,866**	26,645	**207,165**	203,809
Industrial	**10,070**	9,289	**98,828**	97,429
Other	**519**	492	**1,605**	1,598
Total retail sales	**83,258**	76,062	**588,628**	573,261
Resale sales	**7,695**	11,339	**189,895**	223,100
Provision for rate refund	**3,391**	125	**0**	0
Other operating revenues	**2,741**	3,481	**0**	0
Total operating revenues	**$97,085**	$91,007	**778,523**	796,361

2011 vs. 2010
Operating revenues increased by $6.1 million for the three months ended March 31, 2011 compared to the same period in 2010 due to the following factors:

- Retail sales increased $7.2 million resulting primarily from a 7.46 percent base rate increase effective January 1, 2011 and higher customer usage due to colder weather in 2011.
- Resale sales decreased $3.6 million 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 $3.3 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 increase included the favorable impact of $3.4 million of net deferrals and refunds in 2011 vs. the favorable impact of $0.1 million of net deferrals and refunds in 2010.
- Other operating revenues decreased $0.8 million mostly due to mutual aid for other utilities in 2010.

Purchased Power - affiliates and other: Purchased power expense and volume for the three months ended March 31 are summarized below:

	Purchases (in thousands)		MWh purchases	
	2011	2010	**2011**	2010
VYNPC	**$17,056**	$16,228	**390,805**	387,555
Hydro-Quebec	**16,526**	16,608	**265,007**	267,625
Independent Power Producers	**6,279**	6,346	**48,382**	50,194
Subtotal long-term contracts	**39,861**	39,182	**704,194**	705,374
Other purchases	**1,122**	2,366	**1,444**	13,961
Reserve for loss on power contract	**(299)**	(299)	**0**	0
Nuclear decommissioning	**356**	330	**0**	0
Other	**312**	139	**0**	0
Total purchased power	**$41,352**	$41,718	**705,638**	719,335

2011 vs. 2010
Purchased power expense decreased $0.4 million for the three months ended March 31, 2011 compared to the same period in 2010 due to the following factors:

- Purchased power costs under long-term contracts increased $0.7 million in 2011, due primarily to higher output at the Vermont Yankee plant, lower volume from Hydro-Québec and decreased purchases from Independent Power Producers.
- Other purchases decreased $1.2 million due to lower capacity costs and decreased volumes at lower market prices.
- Nuclear decommissioning costs increased less than $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 increased $0.2 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.

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 $0.9 million was principally due to higher VTA billings due to higher specific facility charges, partially offset by higher NOATT reimbursements under the VTA.

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 $2.7 million was primarily due to $3 million of higher net regulatory amortizations, largely due to $4.1 million of exogenous costs, related to major storms and tax law changes.

Maintenance: These expenses are associated with maintaining our electric distribution system and include costs of our jointly owned generation and transmission facilities. The decrease of $2 million was largely due to lower service restoration costs in 2011 vs. major storms in 2010.

Income tax expense: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods. The effective combined federal and state income tax rate for 2011 is 38 percent compared to 44.9 percent for 2010. The variance includes the impact of the PPACA, as modified by the Health Care and Education Reconciliation Act, which represented 9 percent of the 2010 effective tax rate.

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 less than $0.1 million for the first three months of 2011 compared to $0.1 million in 2010. Significant variances in line items that comprise other income and other deductions on the Condensed Consolidated Statements of Income are described below.

Equity in earnings of affiliates: These are earnings on our equity investments including VELCO, Transco and VYNPC. The increase of $1.5 million for the first three months of 2011 versus 2010 is principally due to the return on the $34.9 million investment that we made in Transco in December 2010.

Income Tax Expense: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods. The increase of $0.7 million for the first three months of 2011 versus 2010 resulted primarily from a higher level of earnings from Transco.

<u>POWER SUPPLY MATTERS</u>

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

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

Our current power forecast suggests we have excess energy supply during 2011 and early 2012. In 2010, we conducted a successful online auction to sell most of our projected excess energy for 2011 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.

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

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

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

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

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

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

The obligations of HQUS and each Buyer are contingent upon the receipt of certain governmental approvals. On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. 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, which we plan to execute as proposed. In the event the HQUS PPA is terminated with respect to any Buyer as a result of such Buyer's failure to receive governmental approvals, each of the other Buyers will have an option to purchase the additional energy.

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

Vermont Yankee: Under Vermont law, in addition to a favorable Vermont legislative vote, the PSB needs to issue a Certificate of Public Good for the plant to continue to operate after March 21, 2012. 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. The new Vermont Legislature elected on November 2, 2010 could vote differently, although the political makeup of the House and Senate remains largely unchanged and there is nothing to suggest that a new vote will be held. Also, Vermont elected a new governor who advocated as a member of the Vermont Senate and during the gubernatorial campaign that the Vermont Yankee plant should close when its current license expires, and he maintains that position.

After the November election, Entergy announced it had begun pursuing the sale of the plant, apparently concluding that the plant had a better chance at remaining part of Vermont's power supply under new ownership. We did everything in our power in the context of contract talks with Entergy-Vermont Yankee for the specific purpose of increasing the chances the plant would continue to operate beyond 2012. On March 29, 2011, Entergy announced its sale process had concluded unsuccessfully. Consequently, the potential for state legislative and regulatory approval of continued plant operations is now, in our view, less likely. However, as discussed more fully below, Entergy-Vermont Yankee is seeking to operate the plant beyond March 21, 2012, without such approvals.

On March 10, 2011, the NRC voted 4-0 to approve the 20-year license extension through March 21, 2032 requested by Entergy-Vermont Yankee. This approval removes the last federal-level regulatory requirement for relicensing of the Vermont Yankee station.

Entergy-Vermont Yankee, previously attempting to overcome legislative concerns, recently challenged the state's authority as it relates to relicensing. In a federal lawsuit filed on April 18, 2011, Entergy-Vermont Yankee contended that the state was improperly attempting to interfere with its relicensing. In the complaint filed in U.S. District Court for the District of Vermont, Entergy-Vermont Yankee is seeking 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 seeks both declaratory and injunctive relief, and contends that Vermont's attempts to shutter the plant are preempted by the Atomic Energy Act, the Federal Power Act and the Commerce Clause of the U.S. Constitution. The state of Vermont has vowed to vigorously defend its position. The federal court has scheduled a pretrial status conference for May 5, 2011, during which time procedural matters will be discussed including the litigation schedule. We are evaluating the potential impact of the litigation on our financial statements and on our customers. The outcome of this matter is uncertain at this time.

RECENT ENERGY POLICY INITIATIVES

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

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

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

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

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

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 Condensed 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 our Annual Report on Form 10-K for the year ended December 31, 2010. Also, see Note 2 - Summary of Significant Accounting Policies to the accompanying Notes to Condensed 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 many projects in 2011; however, it will consider staggering the effective dates of new standards to ensure an orderly transition to any new requirements. We have not yet evaluated the impact, if any, that the adoption of the new standards may have on our consolidated financial statements.

On February 24, 2010, the SEC issued a statement of its position regarding global accounting standards. Among other things, the SEC stated that it has directed its staff to execute a work plan, which will include consideration of IFRS as it exists today and after the completion of various convergence projects currently underway between U.S. and international accounting standards-setters. During 2011, the SEC is expected to provide an update on their work plan. If the SEC determines in 2011 to move forward with IFRS, the first time that U.S. companies would report under such a system would be no earlier than 2015. If so, since we are an accelerated filer, we would be required to adopt IFRS in 2016.

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 SEC has issued proposed rules for certain provisions that are scheduled to be approved by the end of 2011. We have already implemented changes related to non-binding shareholder advisory votes on executive compensation and compensation and benefit plan risk assessments.

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

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the three months ended March 31, 2011, there were no material changes from the disclosures included in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2010, except as shown below.

Power-related derivatives We account for some of our power contracts as derivatives under FASB's guidance for derivatives and hedging. These derivatives are described in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates. Summarized information related to the fair value of power contract derivatives is shown in the table below (dollars in thousands):

	Financial Transmission Rights
Total fair value at December 31, 2010	$28
Gains and losses (realized and unrealized)	
Included in earnings	(7)
Included in Regulatory and other assets/liabilities	60
Purchases, sales, issuances and net settlements	0
Total fair value at March 31, 2011	$81
Estimated fair value at March 31, 2011 for changes in projected market price:	
10 percent increase	$8
10 percent decrease	($8)

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 Condensed 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.

Equity Market Risk As of March 31, 2011, our pension trust held marketable equity securities of $59.3 million, our postretirement medical trust funds held marketable equity securities of $11.6 million, our Millstone Unit #3 decommissioning trust held marketable equity securities of $4.6 million and our Rabbi Trust held variable life insurance policies with underlying marketable equity securities of $2.8 million. These equity investments experienced positive performance through March 31, 2011 and positive performance in 2010. Also see Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, and Note 12 - Pension and Postretirement Medical Benefits for additional information.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Management of the company, under the supervision and with participation of our Chief Executive Officer and Principal Financial and Accounting Officer, conducted an evaluation of the effectiveness of the design and operation of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")), as of March 31, 2011. Based on this evaluation, our Chief Executive Officer and Principal Financial and Accounting Officer concluded that, as of March 31, 2011, the company's disclosure controls and procedures are effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting There were no changes in internal control over financial reporting that occurred during the quarter ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

The company is involved in legal and administrative proceedings in the normal course of business and does not believe that the ultimate outcome of these proceedings will have a material adverse effect on its financial position, results of operations or cash flows.

Item 1A. Risk Factors.

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 recent 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 we have an ownership interest in, if an incident did occur, it could have a material adverse effect on our financial position, results of operations and cash flows.

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I "Item 1A. Risk Factors", in our Annual Report on Form 10-K for the year ended December 31, 2010, which could materially affect our business, financial condition or future results.

Item 6. Exhibits.

(a) List of Exhibits

4.12 Bond Purchase Agreement, dated as of February 4, 2011, between the Company and Metropolitan Life Insurance Company. (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed with the SEC on February 4, 2011)

A 10.19 Consulting Services Agreement between Robert H. Young and Central Vermont Public Service Corporation dated effective June 1, 2011. (incorporated by reference to Exhibit A 10.19 to the Company's Form 8-K filed with the SEC on April 22, 2011)

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

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

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

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
(Registrant)

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

Dated May 5, 2011