(c) Lease Commitments

The following table sets forth information concerning CenterPoint Energy's obligations under non-cancelable long-term operating leases at December 31, 2009, which primarily consist of rental agreements for building space, data processing equipment and vehicles (in millions):

2010	$	12
2011		13
2012		9
2013		6
2014		4
2015 and beyond		7
Total	$	51

Total lease expense for all operating leases was $48 million, $46 million and $37 million during 2007, 2008 and 2009, respectively.

(d) Other Commitments

In December 2008, CenterPoint Energy entered into an agreement to purchase software licenses, support and maintenance over the next five years. As of December 31, 2009, payment obligations under this agreement are $7 million in 2010, $6 million in 2011, $6 million in 2012 and $6 million in 2013.

Long-Term Gas Gathering and Treating Agreements. In September 2009, CenterPoint Energy Field Services, Inc. (CEFS), a wholly-owned natural gas gathering and treating subsidiary of CERC Corp., entered into long-term agreements with an indirect wholly-owned subsidiary of EnCana Corporation (EnCana) and an indirect wholly-owned subsidiary of Royal Dutch Shell plc (Shell) to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Louisiana. CEFS also acquired jointly-owned gathering facilities from EnCana and Shell in De Soto and Red River parishes in northwest Louisiana. Each of the agreements includes acreage dedication and volume commitments for which CEFS has rights to gather Shell's and EnCana's natural gas production from the dedicated areas.

In connection with the agreements, CEFS commenced gathering and treating services utilizing the acquired facilities. CEFS is expanding the acquired facilities in order to gather and treat up to 700 million cubic feet (MMcf) per day of natural gas. If EnCana or Shell elect, CEFS will further expand the facilities in order to gather and treat additional future volumes. The construction necessary to reach the contractual capacity of 700 MMcf per day includes more than 200 miles of gathering lines, nearly 25,500 horsepower of compression and over 800 MMcf per day of treating capacity.

CEFS estimates that the purchase of existing facilities and construction to gather 700 MMcf per day will cost up to $325 million. If EnCana and Shell elect expansion of the project to gather and process additional future volumes of up to 1 Bcf per day, CEFS estimates that the expansion would cost as much as an additional $300 million and EnCana and Shell would provide incremental volume commitments. Funds for construction are being provided from anticipated cash flows from operations, lines of credit or proceeds from the sale of debt or equity securities. As of December 31, 2009, approximately $176 million has been spent on this project, including the purchase of existing facilities.

(e) Legal, Environmental and Other Regulatory Matters

Legal Matters

Gas Market Manipulation Cases . CenterPoint Energy, CenterPoint Houston or their predecessor, Reliant Energy, Incorporated (Reliant Energy), and certain of their former subsidiaries are named as defendants in several lawsuits described below. Under a master separation agreement between CenterPoint Energy and RRI (formerly known as Reliant Resources, Inc. and Reliant Energy, Inc.), CenterPoint Energy and its subsidiaries are entitled to be indemnified by RRI for any losses, including attorneys' fees and other costs, arising out of these lawsuits. Pursuant to the indemnification obligation, RRI is defending CenterPoint Energy and its subsidiaries to the extent named in these lawsuits. A large number of lawsuits were filed against numerous gas market participants in a number of federal and western state courts in connection with the operation of the natural gas markets in 2000-2002. CenterPoint Energy's former affiliate, RRI, was a participant in gas trading in the California and Western markets. These lawsuits, many of which have been filed as class actions, allege violations of state and federal antitrust laws. Plaintiffs in these lawsuits are seeking a variety of forms of relief, including, among others, recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages, full consideration damages and attorneys' fees. CenterPoint Energy and/or Reliant Energy were named in approximately 30 of these lawsuits, which were instituted between 2003 and 2009. CenterPoint Energy and its affiliates have been released or dismissed from all but two of such cases. CenterPoint Energy Services, Inc. (CES), a subsidiary of CERC Corp., is a defendant in a case now pending in federal court in Nevada alleging a conspiracy to inflate Wisconsin natural gas prices in 2000-2002. Additionally, CenterPoint Energy was a defendant in a lawsuit filed in state court in Nevada that was dismissed in 2007, but the plaintiffs have indicated that they will appeal the dismissal. CenterPoint Energy believes that neither it nor CES is a proper defendant in these remaining cases and will continue to pursue dismissal from those cases. CenterPoint Energy does not expect the ultimate outcome of these remaining matters to have a material impact on its financial condition, results of operations or cash flows.

On May 1, 2009, RRI completed the previously announced sale of its Texas retail business to NRG Retail LLC, a subsidiary of NRG Energy, Inc. In connection with the sale, RRI changed its name to RRI Energy, Inc. and no longer provides service as a REP in CenterPoint Houston's service territory. The sale does not alter RRI's contractual obligations to indemnify CenterPoint Energy and its subsidiaries, including CenterPoint Houston, for certain liabilities, including their indemnification regarding certain litigation, nor does it affect the terms of existing guaranty arrangements for certain RRI gas transportation contracts.

Natural Gas Measurement Lawsuits. CERC Corp. and certain of its subsidiaries, along with 76 other natural gas pipelines, their subsidiaries and affiliates, were defendants in a lawsuit filed in 1997 under the Federal False Claims Act alleging mismeasurement of natural gas produced from federal and Indian lands. The suit sought undisclosed damages, along with statutory penalties, interest, costs and fees. This case was consolidated, together with the other similar False Claims Act cases, in the federal district court in Cheyenne, Wyoming. In October 2006, the judge considering this matter granted the defendants' motion to dismiss the suit on the ground that the court lacked subject matter jurisdiction over the claims asserted. The plaintiff sought review of that dismissal from the Tenth Circuit Court of Appeals, which affirmed the district court's dismissal in March 2009. Following dismissal of the plaintiff's motion to the Tenth Circuit for rehearing, the plaintiff sought review by the United States Supreme Court, but his petition for certiorari was denied in October 2009.

In addition, CERC Corp. and certain of its subsidiaries are defendants in two mismeasurement lawsuits brought against approximately 245 pipeline companies and their affiliates pending in state court in Stevens County, Kansas. In one case (originally filed in May 1999 and amended four times), the plaintiffs purport to represent a class of royalty owners who allege that the defendants have engaged in systematic mismeasurement of the volume of natural gas for more than 25 years. The plaintiffs amended their petition in this suit in July 2003 in response to an order from the judge denying certification of the plaintiffs' alleged class. In the amendment, the plaintiffs dismissed their claims against certain defendants (including two CERC Corp. subsidiaries), limited the scope of the class of plaintiffs they purport to represent and eliminated previously asserted claims based on mismeasurement of the British thermal unit (Btu) content of the gas. The same plaintiffs then filed a second lawsuit, again as representatives of a putative class of royalty owners in which they assert their claims that the defendants have engaged in systematic mismeasurement of the Btu content of natural gas for more than 25 years. In both lawsuits, the plaintiffs seek compensatory damages, along with statutory penalties, treble damages, interest, costs and fees. In September 2009, the district court in Stevens County, Kansas, denied plaintiffs' request for class certification of their case. The plaintiffs are seeking reconsideration of that denial.

CERC believes that there has been no systematic mismeasurement of gas and that these lawsuits are without merit. CERC and CenterPoint Energy do not expect the ultimate outcome of the lawsuits to have a material impact on the financial condition, results of operations or cash flows of either CenterPoint Energy or CERC.

Gas Cost Recovery Litigation. In October 2004, a lawsuit was filed by certain CERC ratepayers in Texas and Arkansas in circuit court in Miller County, Arkansas against CenterPoint Energy, CERC Corp., certain other subsidiaries of CenterPoint Energy and CERC Corp. and various non-affiliated companies alleging fraud, unjust enrichment and civil conspiracy with respect to rates charged to certain consumers of natural gas in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. Although the plaintiffs in the Miller County case sought class certification, no class was certified. In June 2007, the Arkansas Supreme Court determined that the Arkansas claims were within the sole and exclusive jurisdiction of the Arkansas Public Service Commission (APSC) and in February 2008, the Arkansas Supreme Court directed the Miller County court to dismiss the entire case for lack of jurisdiction.

In August 2007, the Arkansas plaintiff in the Miller County litigation initiated a complaint at the APSC seeking a decision concerning the extent of the APSC's jurisdiction over the Miller County case and an investigation into the merits of the allegations asserted in his complaint with respect to CERC. In February 2009, the Arkansas plaintiff notified the APSC that he would no longer pursue his claims, and in July 2009 the complaint proceeding was dismissed by the APSC. All appellate deadlines expired without an appeal of the dismissal order.

In June 2007, CenterPoint Energy, CERC Corp., and other defendants in the Miller County case filed a petition in a district court in Travis County, Texas seeking a determination that the Railroad Commission has exclusive original jurisdiction over the Texas claims asserted in the Miller County case. In January 2009, the district court entered a final declaratory judgment ruling that the Railroad Commission has exclusive jurisdiction over the Texas claims asserted against CenterPoint Energy, and the other defendants in the Miller County case.

Environmental Matters

Manufactured Gas Plant Sites. CERC and its predecessors operated manufactured gas plants (MGPs) in the past. In Minnesota, CERC has completed remediation on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in CERC's Minnesota service territory. CERC believes that it has no liability with respect to two of these sites.

At December 31, 2009, CERC had accrued $14 million for remediation of these Minnesota sites and the estimated range of possible remediation costs for these sites was $4 million to $35 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. CERC has utilized an environmental expense tracker mechanism in its rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2009, CERC had collected $13 million from insurance companies and rate payers to be used for future environmental remediation. In January 2010, as part of its Minnesota rate case decision, the MPUC eliminated the environmental expense tracker mechanism and ordered amounts previously collected from ratepayers and related carrying costs refunded to customers. As of December 31, 2009, the balance in the environmental expense tracker account was $8.7 million. The MPUC provided for the inclusion in rates of approximately $285,000 annually to fund normal on-going remediation costs. CERC was not required to refund to customers the amount collected from insurance companies, $4.6 million at December 31, 2009, to be used to mitigate future environmental costs. The MPUC further gave assurance that any reasonable and prudent environmental clean-up costs CERC incurs in the future will be rate-recoverable under normal regulatory principles and procedures. This provision had no impact on earnings.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. CERC has been named as a defendant in a lawsuit filed in the United States District Court, District of Maine, under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of CERC or its divisions. CERC has also been identified as a PRP by the State of Maine for a site that is the subject of the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing would be required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. In September 2009, the federal district court granted CERC's motion for summary judgment in the proceeding. Although it is likely that the plaintiff will pursue an appeal from that dismissal, further action will not be taken until the district court disposes of claims against other defendants in the case. CERC believes it is not liable as a former owner or operator of the site under the Comprehensive Environmental, Response, Compensation and Liability Act of 1980, as amended, and applicable state statutes, and is vigorously contesting the suit and its designation as a PRP. CERC and CenterPoint Energy do not expect the ultimate outcome to have a material adverse impact on the financial condition, results of operations or cash flows of either CenterPoint Energy or CERC.

Mercury Contamination. CenterPoint Energy's pipeline and distribution operations have in the past employed elemental mercury in measuring and regulating equipment. It is possible that small amounts of mercury may have been spilled in the course of normal maintenance and replacement operations and that these spills may have contaminated the immediate area with elemental mercury. CenterPoint Energy has found this type of contamination at some sites in the past, and CenterPoint Energy has conducted remediation at these sites. It is possible that other contaminated sites may exist and that remediation costs may be incurred for these sites. Although the total amount of these costs is not known at this time, based on CenterPoint Energy's experience and that of others in the natural gas industry to date and on the current regulations regarding remediation of these sites, CenterPoint Energy believes that the costs of any remediation of these sites will not be material to CenterPoint Energy's financial condition, results of operations or cash flows.

Asbestos. Some facilities owned by CenterPoint Energy contain or have contained asbestos insulation and other asbestos-containing materials. CenterPoint Energy or its subsidiaries have been named, along with numerous others, as a defendant in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos. Some of the claimants have worked at locations owned by CenterPoint Energy, but most existing claims relate to facilities previously owned by CenterPoint Energy's subsidiaries. CenterPoint Energy anticipates that additional claims like those received may be asserted in the future. In 2004, CenterPoint Energy sold its generating business, to which most of these claims relate, to Texas Genco LLC, which is now known as NRG Texas LP. Under the terms of the arrangements regarding separation of the generating business from CenterPoint Energy and its sale to NRG Texas LP, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by NRG Texas LP, but CenterPoint Energy has agreed to continue to defend such claims to the extent they are covered by insurance maintained by CenterPoint Energy, subject to reimbursement of the costs of such defense from NRG Texas LP. Although their ultimate outcome cannot be predicted at this time, CenterPoint Energy intends to continue vigorously contesting claims that it does not consider to have merit and does not expect, based on its experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on CenterPoint Energy's financial condition, results of operations or cash flows.

Groundwater Contamination Litigation. Predecessor entities of CERC, along with several other entities, are defendants in litigation, *St. Michel Plantation, LLC, et al, v. White, et al .*, pending in civil district court in Orleans Parish, Louisiana. In the lawsuit, the plaintiffs allege that their property in Terrebonne Parish, Louisiana suffered salt water contamination as a result of oil and gas drilling activities conducted by the defendants. Although a predecessor of CERC held an interest in two oil and gas leases on a portion of the property at issue, neither it nor any other CERC entities drilled or conducted other oil and gas operations on those leases. In January 2009, CERC and the plaintiffs reached agreement on the terms of a settlement that, if ultimately approved by the Louisiana Department of Natural Resources, is expected to resolve this litigation. CenterPoint Energy and CERC do not expect the outcome of this litigation to have a material adverse impact on the financial condition, results of operations or cash flows of either CenterPoint Energy or CERC.

Other Environmental. From time to time CenterPoint Energy has received notices from regulatory authorities or others regarding its status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, CenterPoint Energy has been named from time to time as a defendant in litigation related to such sites. Although the ultimate outcome of such matters cannot be predicted at this time, CenterPoint Energy does not expect, based on its experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on CenterPoint Energy's financial condition, results of operations or cash flows.

Other Proceedings

CenterPoint Energy is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. CenterPoint Energy regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. CenterPoint Energy does not expect the disposition of these matters to have a material adverse effect on CenterPoint Energy's financial condition, results of operations or cash flows.

In December 2009, $3.3 million was distributed to a subsidiary of CenterPoint Energy in connection with the settlement of 2002 AOL Time Warner, Inc. securities and ERISA class action litigation. Pursuant to the terms of the indenture governing CenterPoint Energy's ZENS, in February 2010, CenterPoint Energy distributed to current ZENS holders $2.8 million, which amount represented the portion of the payment received that was attributable to the reference shares corresponding to the outstanding ZENS. This distribution reduced the contingent principal amount of the ZENS from $814 million to $811 million. The litigation settlement was recorded as other income and the distribution payable to ZENS holders was recorded as other expense in 2009.

(f) Guaranties

Prior to CenterPoint Energy's distribution of its ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI's trading subsidiary. When the companies separated, RRI agreed to secure CERC against obligations under the guaranties RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI has agreed to provide to CERC cash or letters of credit as security against CERC's obligations under its remaining guaranties for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose CERC to a risk of loss on those guaranties. The present value of the demand charges under these transportation contracts, which will be effective until 2018, was approximately $96 million as of December 31, 2009. As of December 31, 2009, RRI was not required to provide security to CERC. If RRI should fail to perform the contractual obligations, CERC could have to honor its guarantee and, in such event, collateral provided as security may be insufficient to satisfy CERC's obligations.

(11) Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents, investments in debt and equity securities classified as "available-for-sale" and "trading" and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair values of non-trading derivative assets and liabilities and the ZENS indexed debt securities derivative are stated at fair value and are excluded from the table below. The fair value of each debt instrument is determined by multiplying the principal amount of each debt instrument by the market price.

	December 31, 2008		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Financial liabilities:				
Long-term debt	$ 10,396	$ 9,875	$ 9,900	$ 10,413

(12) Earnings Per Share

The following table reconciles numerators and denominators of CenterPoint Energy's basic and diluted earnings per share calculations:

	For the Year Ended December 31, 2007	2008	2009
	(In millions, except per share and share amounts)		
Basic earnings per share calculation:			
Net income	$ 395	$ 446	$ 372
Weighted average shares outstanding	320,480,000	336,387,000	365,229,000
Basic earnings per share	$ 1.23	$ 1.32	$ 1.02
Diluted earnings per share calculation:			
Net income	$ 395	$ 446	$ 372
Weighted average shares outstanding	320,480,000	336,387,000	365,229,000
Plus: Incremental shares from assumed conversions:			
Stock options(1)	1,059,000	760,000	451,000
Restricted stock	1,928,000	1,772,000	2,001,000
2.875% convertible senior notes	291,000	-	-
3.75% convertible senior notes	18,749,000	4,636,000	-
Weighted average shares assuming dilution	342,507,000	343,555,000	367,681,000
Diluted earnings per share	$ 1.15	$ 1.30	$ 1.01

(1) Options to purchase 3,225,969, 2,617,772 and 2,372,132 shares were outstanding for the years ended December 31, 2007, 2008 and 2009, respectively, but were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares for the respective years.

Substantially all of the 3.75% contingently convertible senior notes provided for settlement of the principal portion in cash rather than stock. The portion of the conversion value of such notes that was required to be settled in cash rather than stock is excluded from the computation of diluted earnings per share from continuing operations. CenterPoint Energy included the conversion spread in the calculation of diluted earnings per share when the average market price of CenterPoint Energy's common stock in the respective reporting period exceeded the conversion price. In April 2008, CenterPoint Energy called its 3.75% convertible senior notes for redemption on May 30, 2008. Substantially all of CenterPoint Energy's 3.75% convertible senior notes were submitted for conversion on or prior to the May 30, 2008 redemption date.

(13) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2008 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Revenues	$ 3,363	$ 2,670	$ 2,515	$ 2,774
Operating income	336	297	337	303
Net income	122	101	136	87
Basic earnings per share(1)	$ 0.37	$ 0.30	$ 0.40	$ 0.25
Diluted earnings per share(1)	$ 0.36	$ 0.30	$ 0.39	$ 0.25

	Year Ended December 31, 2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Revenues	$ 2,766	$ 1,640	$ 1,576	$ 2,299
Operating income	285	253	287	299
Net income	67	86	114	105
Basic earnings per share(1)	$ 0.19	$ 0.24	$ 0.31	$ 0.27
Diluted earnings per share(1)	$ 0.19	$ 0.24	$ 0.31	$ 0.27

(1) Quarterly earnings per common share are based on the weighted average number of shares outstanding during the quarter, and the sui the quarters may not equal annual earnings per common share. CenterPoint Energy included the conversion spread related tc contingently convertible senior notes in the calculation of diluted earnings per share when the average market price of CenterI Energy's common stock in the respective reporting period exceeds the conversion price. All of CenterPoint Energy's 3.75% conver senior notes were submitted for conversion on or prior to the May 30, 2008 redemption date.

(14) Reportable Business Segments

CenterPoint Energy's determination of reportable business segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting policies except that some executive benefit costs have not been allocated to business segments. CenterPoint Energy uses operating income as the measure of profit or loss for its business segments.

CenterPoint Energy's reportable business segments include the following: Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. The electric transmission and distribution function (CenterPoint Houston) is reported in the Electric Transmission & Distribution business segment. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers. Competitive Natural Gas Sales and Services represents CenterPoint Energy's non-rate regulated gas sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. The Interstate Pipelines business segment includes the interstate natural gas pipeline operations. The Field Services business segment includes the natural gas gathering, treating and processing operations. Other Operations consists primarily of other corporate operations which support all of CenterPoint Energy's business operations.

Long-lived assets include net property, plant and equipment, net goodwill and other intangibles and equity investments in unconsolidated subsidiaries. Intersegment sales are eliminated in consolidation.

Financial data for business segments and products and services are as follows (in millions):

	Revenues from External Customers	Intersegment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2007:						
Electric Transmission & Distribution	$ 1,837(1)	$ -	$ 398	$ 561	$ 8,358	$ 401
Natural Gas Distribution	3,749	10	155	218	4,332	191
Competitive Natural Gas Sales and Services	3,534	45	5	75	1,221	7
Interstate Pipelines(2)	357	143	44	237	3,007	308
Field Services(3)	136	39	11	99	669	74
Other	10	-	18	(5)	1,956(4)	30
Reconciling Eliminations	-	(237)	-	-	(1,671)	-
Consolidated	$ 9,623	$ -	$ 631	$ 1,185	$ 17,872	$ 1,011
As of and for the year ended December 31, 2008:						
Electric Transmission & Distribution	$ 1,916(1)	$ -	$ 460	$ 545	$ 8,880	$ 481(5)
Natural Gas Distribution	4,217	9	157	215	4,961	214
Competitive Natural Gas Sales and Services	4,488	40	3	62	1,315	8
Interstate Pipelines(2)	477	173	46	293	3,578	189
Field Services(3)	213	39	12	147	826	122
Other	11	-	30	11	2,185(4)	39
Reconciling Eliminations	-	(261)	-	-	(2,069)	-
Consolidated	$ 11,322	$ -	$ 708	$ 1,273	$ 19,676	$ 1,053
As of and for the year ended December 31, 2009:						
Electric Transmission & Distribution	$ 2,013(1)	$ -	$ 480	$ 545	$ 9,755	$ 428(5)
Natural Gas Distribution	3,374	10	161	204	4,535	165
Competitive Natural Gas Sales and Services	2,215	15	4	21	1,176	2
Interstate Pipelines(2)	456	142	48	256	3,484	176
Field Services(3)	212	29	15	94	1,045	348
Other	11	-	35	4	2,261(4)	29
Reconciling Eliminations	-	(196)	-	-	(2,483)	-
Consolidated	$ 8,281	$ -	$ 743	$ 1,124	$ 19,773	$ 1,148

(1) Sales to subsidiaries of NRG Retail LLC, the successor to RRI's Texas retail business, in 2007, 2008 and 2009 represented approximately $661 million, $635 million and $634 million, respectively, of CenterPoint Houston's transmission and distribution revenues.

(2) Interstate Pipelines recorded equity income of $6 million, $36 million, and $7 million (including $6 million and $33 million related to pre-operating allowance for funds used during construction during 2007 and 2008, respectively) in the years ended December 31, 2007, 2008 and 2009, respectively, from its 50% interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Interstate Pipelines' investment in SESH was $58 million, $307 million and $422 million as of December 31, 2007, 2008 and 2009 and is included in Investment in unconsolidated affiliates.

(3) Field Services recorded equity income of $10 million, $15 million and $8 million for the years ended December 31, 2007, 2008 and 2009, respectively, from its 50% interest in a jointly-owned gas processing plant. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Field Services' investment in the jointly-owned gas processing plant was $30 million, $38 million and $40 million as of December 31, 2007, 2008 and 2009, respectively, and is included in Investment in unconsolidated affiliates.

(4) Included in total assets of Other Operations as of December 31, 2007 are pension assets of $231 million. Also included in total assets of Other Operations as of December 31, 2007, 2008 and 2009, are pension and other postemployment related regulatory assets of $319 million, $800 million and $731 million, respectively.

(5) Included in expenditures for long-lived assets of Electric Transmission & Distribution is $145 million and $26 million for 2008 and 2009, respectively, related to Hurricane Ike. Approximately $153 million of distribution related storm restoration costs was reclassified to regulatory assets and was included in the $665 million securitized storm restoration costs as further discussed in Note 3(a). The remaining $18 million of transmission related storm restoration costs is included in plant in service as of December 31, 2009, and is eligible for recovery through the existing mechanisms established to recover transmission costs as further discussed in Note 3(a).

Revenues by Products and Services:	Year Ended December 31, 2007	2008	2009
		(In millions)	
Electric delivery sales	$ 1,837	$ 1,916	$ 2,013
Retail gas sales	4,941	6,216	4,540
Wholesale gas sales	2,196	2,295	902
Gas transport	532	756	691
Energy products and services	117	139	135
Total	$ 9,623	$ 11,322	$ 8,281

(15) Subsequent Events

On January 21, 2010, CenterPoint Energy's board of directors declared a regular quarterly cash dividend of $0.195 per share of common stock payable on March 10, 2010, to shareholders of record as of the close of business on February 16, 2010.

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

None.

Item 9A. *Controls and Procedures*

Disclosure Controls And Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2009 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information called for by Item 10, to the extent not set forth in "Executive Officers" in Item 1, will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2010 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 11. ***Executive Compensation***

The information called for by Item 11 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2010 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 12 . ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information called for by Item 12 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2010 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 13 . ***Certain Relationships and Related Transactions, and Director Independence***

The information called for by Item 13 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2010 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 14 . ***Principal Accounting Fees and Services***

The information called for by Item 14 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2010 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

PART IV

Item 15 . ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements.

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2009.

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements:

III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 125, which index also includes the management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
CenterPoint Energy, Inc.
Houston, Texas

We have audited the consolidated financial statements of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2009 and 2008, and for each of the three years in the period ended December 31, 2009, and the Company's internal control over financial reporting as of December 31, 2009, and have issued our reports thereon dated February 26, 2010; such reports are included elsewhere in this Form 10-K. Our audits also included the financial statement schedules of the Company listed in the index at Item 15 (a)(2). These financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2010

CENTERPOINT ENERGY, INC.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF CENTERPOINT ENERGY, INC. (PARENT COMPANY)

STATEMENTS OF INCOME

	For the Year Ended December 31,		
	2007	2008	2009
		(In millions)	
Expenses:			
Operation and Maintenance Expenses	$ (17)	$ (12)	$ (17)
Taxes Other than Income	(4)	1	-
Total	(21)	(11)	(17)
Other Income (Expense):			
Interest Income from Subsidiaries	22	12	8
Other Income (Expense)	1	(5)	(2)
Gain (Loss) on Indexed Debt Securities	111	128	(68)
Interest Expense to Subsidiaries	(67)	(38)	(25)
Interest Expense	(225)	(162)	(149)
Distribution to ZENS Holders	(27)	-	(3)
Total	(185)	(65)	(239)
Loss Before Income Taxes	(206)	(76)	(256)
Income Tax Benefit	86	32	113
Loss Before Equity in Subsidiaries	(120)	(44)	(143)
Equity Income of Subsidiaries	515	490	515
Net Income	$ 395	$ 446	$ 372

See CenterPoint Energy, Inc. and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8

CENTERPOINT ENERGY, INC.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF CENTERPOINT ENERGY, INC. (PARENT COMPANY)

BALANCE SHEETS

	December 31, 2008	December 31, 2009
	(In millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ -	$ -
Notes receivable - subsidiaries	82	493
Accounts receivable - subsidiaries	53	72
Other assets	-	16
Total current assets	135	581
Other Assets:		
Investment in subsidiaries	5,161	5,562
Notes receivable - subsidiaries	151	151
Other assets	826	751
Total other assets	6,138	6,464
Total Assets	$ 6,273	$ 7,045
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Notes payable - subsidiaries	$ 21	$ 306
Current portion of long-term debt	117	611
Indexed debt securities derivative	133	201
Accounts payable:		
Subsidiaries	40	17
Other	3	40
Taxes accrued	338	416
Interest accrued	26	29
Other	18	1
Total current liabilities	696	1,621
Other Liabilities:		
Accumulated deferred tax liabilities	138	122
Benefit obligations	426	426
Notes payable - subsidiaries	750	750
Other	7	7
Total non-current liabilities	1,321	1,305
Long-Term Debt	2,234	1,480
Shareholders' Equity:		
Common stock	3	4
Additional paid-in capital	3,158	3,671
Accumulated deficit	(1,008)	(912)
Accumulated other comprehensive loss	(131)	(124)
Total shareholders' equity	2,022	2,639
Total Liabilities and Shareholders' Equity	$ 6,273	$ 7,045

See CenterPoint Energy, Inc. and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8

CENTERPOINT ENERGY, INC.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF CENTERPOINT ENERGY, INC. (PARENT COMPANY)

STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2007	2008	2009
		(In millions)	
Operating Activities:			
Net income	$ 395	$ 446	$ 372
Non-cash items included in net income:			
Equity income of subsidiaries	(515)	(490)	(515)
Deferred income tax expense	52	90	(19)
Amortization of debt issuance costs	50	7	5
Loss (gain) on indexed debt securities	(111)	(128)	68
Changes in working capital:			
Accounts receivable/(payable) from subsidiaries, net	20	(65)	86
Accounts payable	11	-	14
Other current assets	-	2	(16)
Other current liabilities	(50)	(111)	59
Common stock dividends received from subsidiaries	240	746	109
Other	2	(7)	(1)
Net cash provided by operating activities	94	490	162
Investing Activities:			
Short-term notes receivable from subsidiaries	175	134	(411)
Net cash provided by (used in) investing activities	175	134	(411)
Financing Activities:			
Revolving credit facility, net	131	133	(264)
Proceeds from long-term debt	250	300	-
Payments on long-term debt	(295)	(907)	-
Debt issuance costs	(2)	(4)	-
Common stock dividends paid	(218)	(246)	(276)
Proceeds from issuance of common stock, net	22	80	504
Short-term notes payable to subsidiaries	(157)	20	285
Net cash provided by (used in) financing activities	(269)	(624)	249
Net Decrease in Cash and Cash Equivalents	-	-	-
Cash and Cash Equivalents at Beginning of Year	-	-	-
Cash and Cash Equivalents at End of Year	$ -	$ -	$ -

See CenterPoint Energy, Inc. and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8

CENTERPOINT ENERGY, INC.
SCHEDULE I - NOTES TO CONDENSED FINANCIAL INFORMATION (PARENT COMPANY)

(1) *Background.* The condensed parent company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of CenterPoint Energy, Inc. (CenterPoint Energy) appearing in the Annual Report on Form 10-K. Bank facilities at CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp., indirect wholly owned subsidiaries of CenterPoint Energy, limit debt, excluding transition and system restoration bonds, as a percentage of their total capitalization to 65%. These covenants could restrict the ability of these subsidiaries to distribute dividends to CenterPoint Energy.

(2) *New Accounting Pronouncements.* Effective January 1, 2009, CenterPoint Energy adopted new accounting guidance for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) which changed the accounting treatment for convertible securities that the issuer may settle fully or partially in cash and which required retrospective application to all periods presented. Under this new guidance, cash settled convertible securities are separated into their debt and equity components. The value assigned to the debt component is the estimated fair value, as of the issuance date, of a similar debt instrument without the conversion feature, and the difference between the proceeds for the convertible debt and the amount reflected as a debt liability is recorded as additional paid-in capital. As a result, the debt is recorded at a discount reflecting its below-market coupon interest rate. The debt is then subsequently accreted to its par value over its expected life, with the rate of interest that reflects the market rate at issuance being reflected on the income statement. CenterPoint Energy currently has no convertible debt that is within the scope of this new guidance, but did during prior periods presented. The required retrospective implementation of this new guidance had a non-cash effect on net income for prior periods and the Consolidated Balance Sheets when CenterPoint Energy had contingently convertible debt outstanding. The effect on net income for the years ended December 31, 2007 and 2008 was a decrease in net income of $4 million, or $0.02 per basic and diluted share, and $1 million, or $0.01 per basic share and no change per diluted share, respectively. The implementation effect on the Consolidated Balance Sheet as of December 31, 2008 increased Additional Paid-In-Capital and Accumulated Deficit by $23 million.

Effective January 1, 2008, CenterPoint Energy adopted new guidance on accounting for deferred compensation and postretirement benefit aspects of endorsement split-dollar life insurance arrangements which required CenterPoint Energy to recognize the effect of implementation through a cumulative effect adjustment to retained earnings or other components of equity as of the beginning of the year of adoption. CenterPoint Energy calculated the impact as negligible at the time of adoption on January 1, 2008. During 2009, CenterPoint Energy determined that its adoption calculation had omitted the impact that increasing future premium costs would have on the liability and, therefore, it recorded as a cumulative effect adjustment a $15 million correction to decrease investment in subsidiaries and increase accumulated deficit as of January 1, 2008. The effect of the correction is not material to CenterPoint Energy's previously issued financial statements and did not affect CenterPoint Energy's results of operations or cash flows.

(3) *Derivatives.* In December 2007 and January 2008, CenterPoint Energy entered into treasury rate lock derivative instruments (treasury rate locks) having an aggregate notional amount of $300 million and a weighted-average locked U.S. treasury rate on ten-year debt of 4.05%. These treasury rate locks were executed to hedge the ten-year U.S. treasury rate expected to be used in pricing $300 million of fixed-rate debt CenterPoint Energy planned to issue in 2008, because changes in the U.S treasury rate would cause variability in CenterPoint Energy's forecasted interest payments. These treasury rate lock derivatives were designated as cash flow hedges. Accordingly, unrealized gains and losses associated with the treasury rate lock derivative instruments were recorded as a component of accumulated other comprehensive income. In May 2008, CenterPoint Energy settled its treasury rate locks for a payment of $7 million. The $7 million loss recognized upon settlement of the treasury rate locks was recorded as a component of accumulated other comprehensive loss and will be recognized as a component of interest expense over the ten-year life of the related $300 million senior notes issued in May 2008. Amortization of amounts deferred in accumulated other comprehensive loss for the years ended December 31, 2008 and 2009 was less than $1 million. During the years ended December 31, 2007 and 2008, CenterPoint Energy recognized a loss of $2 million and $5 million, respectively, for these treasury rate locks in accumulated other comprehensive loss. Ineffectiveness for the treasury rate locks was not material during the years ended December 31, 2007 and 2008.

(4) *Capital Stock.* During the year ended December 31, 2009, CenterPoint Energy received net proceeds of approximately $280 million from the issuance of 24.2 million common shares in an underwritten public offering, net proceeds of $148 million from the issuance of 14.3 million common shares through a continuous offering program, proceeds of approximately $57 million from the sale of approximately 4.9 million common shares to CenterPoint Energy's defined contribution plan and proceeds of approximately $15 million from the sale of approximately 1.3 million common shares to participants in CenterPoint Energy's enhanced dividend reinvestment plan.

(5) *Long-term Debt.* As of December 31, 2009, CenterPoint Energy had no borrowings and approximately $27 million of outstanding letters of credit under its $1.2 billion credit facility. CenterPoint Energy had no commercial paper outstanding at December 31, 2009. CenterPoint Energy was in compliance with all covenants as of December 31, 2009.

CenterPoint Energy's $1.2 billion credit facility has a first drawn cost of the London Interbank Offered Rate (LIBOR) plus 55 basis points based on CenterPoint Energy's current credit ratings. An additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on the borrower's credit rating. The facility contains a debt (excluding transition and system restoration bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant (as those terms are defined in the facility). Such covenant was modified twice in 2008 to provide additional debt capacity. The second modification was to provide debt capacity pending the financing of system restoration costs following Hurricane Ike. That modification was terminated with CenterPoint Houston's issuance of bonds to securitize such costs in November 2009. In February 2010, CenterPoint Energy amended its credit facility to modify the financial ratio covenant to allow for a temporary increase of the permitted ratio of debt (excluding transition and system restoration bonds) to EBITDA from 5 times to 5.5 times if CenterPoint Houston experiences damage from a natural disaster in its service territory and CenterPoint Energy certifies to the administrative agent that CenterPoint Houston has incurred system restoration costs reasonably likely to exceed $100 million in a calendar year, all or part of which CenterPoint Houston intends to seek to recover through securitization financing. Such temporary increase in the financial ratio covenant would be in effect from the date CenterPoint Energy delivers its certification until the earliest to occur of (i) the completion of the securitization financing, (ii) the first anniversary of CenterPoint Energy's certification or (iii) the revocation of such certification.

CenterPoint Energy's maturities of long-term debt, excluding the ZENS obligation, are $490 million in 2010 and $19 million in 2011. There are no maturities of long-term debt in 2012, 2013 and 2014. Maturities in 2010 include $290 million of pollution control bonds issued on behalf of CenterPoint Energy which were purchased by CenterPoint Energy in January 2010.

(6) *Guaranties.* CenterPoint Energy Services, Inc. (CES) provides comprehensive natural gas sales and services to industrial and commercial customers. In order to hedge their exposure to natural gas prices, CES has entered standard purchase and sale agreements with various counterparties. CenterPoint Energy has guaranteed the payment obligations of CES under certain of these agreements, typically for one-year terms. As of December 31, 2009, CenterPoint Energy had guaranteed $13 million under these agreements.

In September 2009, CenterPoint Energy Field Services, Inc. (CEFS), an indirect wholly-owned subsidiary of CenterPoint Energy, entered into long-term agreements with an indirect wholly-owned subsidiary of EnCana Corporation (EnCana) and an indirect wholly-owned subsidiary of Royal Dutch Shell plc (Shell) to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Louisiana. CEFS also acquired jointly-owned gathering facilities from EnCana and Shell in De Soto and Red River parishes in northwest Louisiana. Each of the agreements includes acreage dedication and volume commitments for which CEFS has rights to gather Shell's and EnCana's natural gas production from the dedicated areas.

In connection with the agreements, CEFS commenced gathering and treating services utilizing the acquired facilities. CEFS is expanding the acquired facilities in order to gather and treat up to 700 million cubic feet (MMcf) per day of natural gas. If EnCana or Shell elect, CEFS will further expand the facilities in order to gather and treat additional future volumes. CenterPoint Energy has guaranteed to fund CEFS' obligations, including the initial expansion of the facilities, under these long-term agreements. CenterPoint Energy's initial guarantee is for $200 million to both Shell and EnCana ($400 million total), however the amount of the guarantee could increase if the facilities are expanded or additional services are added. The amount of the guarantee reduces to $50 million upon completion of the gathering system.

(7) *Non-cash transactions*. During 2008, CenterPoint Energy reduced its payables to subsidiaries, with no net asset restrictions, by $430 million with a corresponding reduction in investment in subsidiaries.

CENTERPOINT ENERGY, INC.

SCHEDULE II -VALUATION AND QUALIFYING ACCOUNTS
For the Three Years Ended December 31, 2009

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions From Reserves (2)	Balance at End of Period
			(In millions)		
Year Ended December 31, 2009:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 35	$ 36	$ -	$ 47	$ 24
Deferred tax asset valuation allowance	5	-	-	-	5
Year Ended December 31, 2008:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 38	$ 54	$ 3	$ 60	$ 35
Deferred tax asset valuation allowance	18	(1)	(12) [1]	-	5
Year Ended December 31, 2007:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 33	$ 45	$ -	$ 40	$ 38
Deferred tax asset valuation allowance	22	(4)	-	-	18

(1) The 2008 change to the deferred tax asset valuation allowance charged to other accounts represents a reduction equal to the related deferred tax asset reduction in 2008 for re-measurement of state tax attributes, net of federal tax benefit. A full valuation allowance for this deferred tax asset was established in prior periods.

(2) Deductions from reserves represent losses or expenses for which the respective reserves were created. In the case of the uncollectible accounts reserve, such deductions are net of recoveries of amounts previously written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 26th day of February, 2010.

CENTERPOINT ENERGY, INC.
(Registrant)

By: /s/ David M. McClanahan
David M. McClanahan
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 26, 2010.

Signature	Title
/s/ DAVID M. MCCLANAHAN David M. McClanahan	President, Chief Executive Officer and Director (Principal Executive Officer and Director)
/s/ GARY L. WHITLOCK Gary L. Whitlock	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ WALTER L. FITZGERALD Walter L. Fitzgerald	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ MILTON CARROLL Milton Carroll	Chairman of the Board of Directors
/s/ DONALD R. CAMPBELL Donald R. Campbell	Director
/s/ DERRILL CODY Derrill Cody	Director
/s/ O. HOLCOMBE CROSSWELL O. Holcombe Crosswell	Director
/s/ MICHAEL P. JOHNSON Michael P. Johnson	Director
/s/ JANIECE M. LONGORIA Janiece M. Longoria	Director
/s/ THOMAS F. MADISON Thomas F. Madison	Director
/s/ ROBERT T. O'CONNELL Robert T. O'Connell	Director
/s/ SUSAN O. RHENEY Susan O. Rheney	Director
/s/ MICHAEL E. SHANNON Michael E. Shannon	Director
/s/ PETER S. WAREING Peter S. Wareing	Director
/s/ SHERMAN M. WOLFF Sherman M. Wolff	Director

CENTERPOINT ENERGY, INC.

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2009

INDEX OF EXHIBITS

Exhibits included with this report are designated by a cross (†); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated by an asterisk (*) are management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K. CenterPoint Energy has not filed the exhibits and schedules to Exhibit 2. CenterPoint Energy hereby agrees to furnish supplementally a copy of any schedule omitted from Exhibit 2 to the SEC upon request.

The agreements included as exhibits are included only to provide information to investors regarding their terms. The agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and such agreements should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2	-Transaction Agreement dated July 21, 2004 among CenterPoint Energy, Utility Holding, LLC, NN Houston Sub, Inc., Texas Genco Holdings, Inc. ("Texas Genco"), HPC Merger Sub, Inc. and GC Power Acquisition LLC	CenterPoint Energy's Form 8-K dated July 21, 2004	1-31447	10.1
3(a)	-Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy's Form 8-K dated July 24, 2008	1-31447	3.2
3(b)	-Amended and Restated Bylaws of CenterPoint Energy	CenterPoint Energy's Form 8-K dated January 20, 2010	1-31447	3.1
4(a)	-Form of CenterPoint Energy Stock Certificate	CenterPoint Energy's Registration Statement on Form S-4	333-69502	4.1
4(b)	-Rights Agreement dated January 1, 2002, between CenterPoint Energy and JPMorgan Chase Bank, as Rights Agent	CenterPoint Energy's Form 10-K for the year ended December 31, 2001	1-31447	4.2
4(c)	-Contribution and Registration Agreement dated December 18, 2001 among Reliant Energy, CenterPoint Energy and the Northern Trust Company, trustee under the Reliant Energy, Incorporated Master Retirement Trust	CenterPoint Energy's Form 10-K for the year ended December 31, 2001	1-31447	4.3
4(d)(1)	-Mortgage and Deed of Trust, dated November 1, 1944 between Houston Lighting and Power Company ("HL&P") and Chase Bank of Texas, National Association (formerly, South Texas Commercial National Bank of Houston), as Trustee, as amended and supplemented by 20 Supplemental Indentures thereto	HL&P's Form S-7 filed on August 25, 1977	2-59748	2(b)

4(d)(2)	-Twenty-First through Fiftieth Supplemental Indentures to Exhibit 4(d)(1)	HL&P's Form 10-K for the year ended December 31, 1989	1-3187	4(a)(2)
4(d)(3)	-Fifty-First Supplemental Indenture to Exhibit 4(d)(1) dated as of March 25, 1991	HL&P's Form 10-Q for the quarter ended June 30, 1991	1-3187	4(a)
4(d)(4)	-Fifty-Second through Fifty-Fifth Supplemental Indentures to Exhibit 4(d)(1) each dated as of March 1, 1992	HL&P's Form 10-Q for the quarter ended March 31, 1992	1-3187	4
4(d)(5)	-Fifty-Sixth and Fifty-Seventh Supplemental Indentures to Exhibit 4(d)(1) each dated as of October 1, 1992	HL&P's Form 10-Q for the quarter ended September 30, 1992	1-3187	4
4(d)(6)	-Fifty-Eighth and Fifty-Ninth Supplemental Indentures to Exhibit 4(d)(1) each dated as of March 1, 1993	HL&P's Form 10-Q for the quarter ended March 31, 1993	1-3187	4
4(d)(7)	-Sixtieth Supplemental Indenture to Exhibit 4(d)(1) dated as of July 1, 1993	HL&P's Form 10-Q for the quarter ended June 30, 1993	1-3187	4
4(d)(8)	-Sixty-First through Sixty-Third Supplemental Indentures to Exhibit 4(d)(1) each dated as of December 1, 1993	HL&P's Form 10-K for the year ended December 31, 1993	1-3187	4(a)(8)
4(d)(9)	-Sixty-Fourth and Sixty-Fifth Supplemental Indentures to Exhibit 4(d)(1) each dated as of July 1, 1995	HL&P's Form 10-K for the year ended December 31, 1995	1-3187	4(a)(9)
4(e)(1)	-General Mortgage Indenture, dated as of October 10, 2002, between CenterPoint Energy Houston Electric, LLC and JPMorgan Chase Bank, as Trustee	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(1)
4(e)(2)	-Second Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10- Q for the quarter ended September 30, 2002	1-3187	4(j)(3)
4(e)(3)	-Third Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(4)
4(e)(4)	-Fourth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10- Q for the quarter ended September 30, 2002	1-3187	4(j)(5)
4(e)(5)	-Fifth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(6)
4(e)(6)	-Sixth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(7)

4(e)(7)	-Seventh Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(8)
4(e)(8)	-Eighth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(9)
4(e)(9)	-Officer's Certificates dated October 10, 2002 setting forth the form, terms and provisions of the First through Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	4(e)(10)
4(e)(10)	-Ninth Supplemental Indenture to Exhibit 4(e)(1), dated as of November 12, 2002	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	4(e)(10)
4(e)(11)	-Officer's Certificate dated November 12, 2003 setting forth the form, terms and provisions of the Ninth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	4(e)(12)
4(e)(12)	-Tenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 18, 2003	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.1
4(e)(13)	-Officer's Certificate dated March 18, 2003 setting forth the form, terms and provisions of the Tenth Series and Eleventh Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.2
4(e)(14)	-Eleventh Supplemental Indenture to Exhibit 4(e)(1), dated as of May 23, 2003	CenterPoint Energy's Form 8-K dated May 16, 2003	1-31447	4.2
4(e)(15)	-Officer's Certificate dated May 23, 2003 setting forth the form, terms and provisions of the Twelfth Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated May 16, 2003	1-31447	4.1
4(e)(16)	-Twelfth Supplemental Indenture to Exhibit 4(e)(1), dated as of September 9, 2003	CenterPoint Energy's Form 8-K dated September 9, 2003	1-31447	4.2
4(e)(17)	-Officer's Certificate dated September 9, 2003 setting forth the form, terms and provisions of the Thirteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated September 9, 2003	1-31447	4.3
4(e)(18)	-Thirteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of February 6, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(16)
4(e)(19)	-Officer's Certificate dated February 6, 2004 setting forth the form, terms and provisions of the Fourteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(17)

4(e)(20)	-Fourteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of February 11, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(18)
4(e)(21)	-Officer's Certificate dated February 11, 2004 setting forth the form, terms and provisions of the Fifteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(19)
4(e)(22)	-Fifteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(20)
4(e)(23)	-Officer's Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Sixteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(21)
4(e)(24)	-Sixteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(22)
4(e)(25)	-Officer's Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Seventeenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(23)
4(e)(26)	-Seventeenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(24)
4(e)(27)	-Officer's Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Eighteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(25)
4(e)(28)	-Nineteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of November 26, 2008	CenterPoint Energy's Form 8-K dated November 25, 2008	1-31447	4.2
4(e)(29)	-Officer's Certificate date November 26, 2008 setting forth the form, terms and provisions of the Twentieth Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated November 25, 2008	1-31447	4.3
4(e)(30)	-Twentieth Supplemental Indenture to Exhibit 4(e)(1), dated as of December 9, 2008	CenterPoint Houston's Form 8-K dated January 6, 2009	1-3187	4.2
4(e)(31)	-Twenty-First Supplemental Indenture to Exhibit 4(e)(1), dated as of January 9, 2009	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	4(e)(31)
4(e)(32)	-Officer's Certificate date January 20, 2009 setting forth the form, terms and provisions of the Twenty-First Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	4(e)(32)

4(f)(1)	-Indenture, dated as of February 1, 1998, between Reliant Energy Resources Corp. ("RERC Corp.") and Chase Bank of Texas, National Association, as Trustee	CERC Corp.'s Form 8-K dated February 5, 1998	1-13265	4.1
4(f)(2)	-Supplemental Indenture No. 1 to Exhibit 4(f)(1), dated as of February 1, 1998, providing for the issuance of RERC Corp.'s 6 1/2% Debentures due February 1, 2008	CERC Corp.'s Form 8-K dated November 9, 1998	1-13265	4.2
4(f)(3)	-Supplemental Indenture No. 2 to Exhibit 4(f)(1), dated as of November 1, 1998, providing for the issuance of RERC Corp.'s 6 3/8% Term Enhanced ReMarketable Securities	CERC Corp.'s Form 8-K dated November 9, 1998	1-13265	4.1
4(f)(4)	-Supplemental Indenture No. 3 to Exhibit 4(f)(1), dated as of July 1, 2000, providing for the issuance of RERC Corp.'s 8.125% Notes due 2005	CERC Corp.'s Registration Statement on Form S-4	333-49162	4.2
4(f)(5)	-Supplemental Indenture No. 4 to Exhibit 4(f)(1), dated as of February 15, 2001, providing for the issuance of RERC Corp.'s 7.75% Notes due 2011	CERC Corp.'s Form 8-K dated February 21, 2001	1-13265	4.1
4(f)(6)	-Supplemental Indenture No. 5 to Exhibit 4(f)(1), dated as of March 25, 2003, providing for the issuance of CenterPoint Energy Resources Corp.'s ("CERC Corp.'s") 7.875% Senior Notes due 2013	CenterPoint Energy's Form 8-K dated March 18, 2003	1-31447	4.1
4(f)(7)	-Supplemental Indenture No. 6 to Exhibit 4(f)(1), dated as of April 14, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	CenterPoint Energy's Form 8-K dated April 7, 2003	1-31447	4.2
4(f)(8)	-Supplemental Indenture No. 7 to Exhibit 4(f)(1), dated as of November 3, 2003, providing for the issuance of CERC Corp.'s 5.95% Senior Notes due 2014	CenterPoint Energy's Form 8-K dated October 29, 2003	1-31447	4.2
4(f)(9)	-Supplemental Indenture No. 8 to Exhibit 4(f)(1), dated as of December 28, 2005, providing for a modification of CERC Corp.'s 6 1/2% Debentures due 2008	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(f)(10)	-Supplemental Indenture No. 9 to Exhibit 4(f)(1), dated as of May 18, 2006, providing for the issuance of CERC Corp.'s 6.15% Senior Notes due 2016	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2006	1-31447	4.7

4(f)(11)	-Supplemental Indenture No. 10 to Exhibit 4(f)(1), dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CenterPoint Energy's Form 10-K for the year ended December 31, 2006	1-31447	4(f)(11)
4(f)(12)	-Supplemental Indenture No. 11 to Exhibit 4(f)(1) dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.125% Senior Notes due 2017	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2007	1-31447	4.8
4(f)(13)	-Supplemental Indenture No. 12 to Exhibit 4(f)(1) dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2008	1-31447	4.9
4(f)(14)	-Supplemental Indenture No. 13 to Exhibit 4(f)(1) dated as of May 15, 2008, providing for the issuance of CERC Corp.'s 6.00% Senior Notes due 2018	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2008	1-31447	4.9
4(g)(1)	-Indenture, dated as of May 19, 2003, between CenterPoint Energy and JPMorgan Chase Bank, as Trustee	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.1
4(g)(2)	-Supplemental Indenture No. 1 to Exhibit 4(g)(1), dated as of May 19, 2003, providing for the issuance of CenterPoint Energy's 3.75% Convertible Senior Notes due 2023	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.2
4(g)(3)	-Supplemental Indenture No. 2 to Exhibit 4(g)(1), dated as of May 27, 2003, providing for the issuance of CenterPoint Energy's 5.875% Senior Notes due 2008 and 6.85% Senior Notes due 2015	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.3
4(g)(4)	-Supplemental Indenture No. 3 to Exhibit 4(g)(1), dated as of September 9, 2003, providing for the issuance of CenterPoint Energy's 7.25% Senior Notes due 2010	CenterPoint Energy's Form 8-K dated September 9, 2003	1-31447	4.2
4(g)(5)	-Supplemental Indenture No. 4 to Exhibit 4(g)(1), dated as of December 17, 2003, providing for the issuance of CenterPoint Energy's 2.875% Convertible Senior Notes due 2024	CenterPoint Energy's Form 8-K dated December 10, 2003	1-31447	4.2
4(g)(6)	-Supplemental Indenture No. 5 to Exhibit 4(g)(1), dated as of December 13, 2004, as supplemented by Exhibit 4(g)(5), relating to the issuance of CenterPoint Energy's 2.875% Convertible Senior Notes due 2024	CenterPoint Energy's Form 8-K dated December 9, 2004	1-31447	4.1

4(g)(7)	-Supplemental Indenture No. 6 to Exhibit 4(g)(1), dated as of August 23, 2005, providing for the issuance of CenterPoint Energy's 3.75% Convertible Senior Notes, Series B due 2023	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(g)(7)
4(g)(8)	-Supplemental Indenture No. 7 to Exhibit 4(g)(1), dated as of February 6, 2007, providing for the issuance of CenterPoint Energy's 5.95% Senior Notes due 2017	CenterPoint Energy's Form 10-K for the year ended December 31, 2006	1-31447	4(g)(8)
4(g)(9)	-Supplemental Indenture No. 8 to Exhibit 4(g)(1), dated as of May 5, 2008, providing for the issuance of CenterPoint Energy's 6.50% Senior Notes due 2018	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2008	1-31447	4.7
4(h)(1)	-Subordinated Indenture dated as of September 1, 1999	Reliant Energy's Form 8-K dated September 1, 1999	1-3187	4.1
4(h)(2)	-Supplemental Indenture No. 1 dated as of September 1, 1999, between Reliant Energy and Chase Bank of Texas (supplementing Exhibit 4(h)(1) and providing for the issuance Reliant Energy's 2% Zero-Premium Exchangeable Subordinated Notes Due 2029)	Reliant Energy's Form 8-K dated September 15, 1999	1-3187	4.2
4(h)(3)	-Supplemental Indenture No. 2 dated as of August 31, 2002, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(h)(1))	CenterPoint Energy's Form 8-K12B dated August 31, 2002	1-31447	4(e)
4(h)(4)	-Supplemental Indenture No. 3 dated as of December 28, 2005, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(h)(1))	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(h)(4)
4(i)(1)	-$1,200,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.3
4(i)(2)	-First Amendment to Exhibit 4(i)(1), dated as of August 20, 2008, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	4.4
4(i)(3)	-Second Amendment to Exhibit 4(i)(1), dated as of November 18, 2008, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy's Form 8-K dated November 18, 2008	1-31447	4.1

4(i)(4)	-Third Amendment to Exhibit 4(i)(1), dated as of February 5, 2010, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy's Form 8-K dated February 5, 2010	1-31447	4.1
4(j)(1)	-$300,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.4
4(j)(2)	-First Amendment to Exhibit 4(j)(1), dated as of November 18, 2008, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy's Form 8-K dated November 18, 2008	1-31447	4.2
4(k)	-$950,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CERC Corp., as Borrower, and the banks named therein	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.5
4(l)	-$600,000,000 Credit Agreement dated as of November 25, 2008, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy's Form 8-K dated November 25, 2008	1-31447	4.1

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, CenterPoint Energy has not filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities authorized does not exceed 10% of the total assets of CenterPoint Energy and its subsidiaries on a consolidated basis. CenterPoint Energy hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(a)	-CenterPoint Energy Executive Benefits Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.4
*10(b)(1)	-Executive Incentive Compensation Plan of Houston Industries Incorporated ("HI") effective as of January 1, 1982	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(b)
*10(b)(2)	-First Amendment to Exhibit 10(b)(1) effective as of March 30, 1992	HI's Form 10-Q for the quarter ended March 31, 1992	1-7629	10(a)
*10(b)(3)	-Second Amendment to Exhibit 10(b)(1) effective as of November 4, 1992	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(b)
*10(b)(4)	-Third Amendment to Exhibit 10(b)(1) effective as of September 7, 1994	HI's Form 10-K for the year ended December 31, 1994	1-7629	10(b)(4)
*10(b)(5)	-Fourth Amendment to Exhibit 10(b)(1) effective as of August 6, 1997	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(b)(5)

*10(c)(1)	-Executive Incentive Compensation Plan of HI as amended and restated on January 1, 1991	HI's Form 10-K for the year ended December 31, 1990	1-7629	10(b)
*10(c)(2)	-First Amendment to Exhibit 10(c)(1) effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(f)(2)
*10(c)(3)	-Second Amendment to Exhibit 10(c)(1) effective as of March 30, 1992	HI's Form 10-Q for the quarter ended March 31, 1992	1-7629	10(d)
*10(c)(4)	-Third Amendment to Exhibit 10(c)(1) effective as of November 4, 1992	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(f)(4)
*10(c)(5)	-Fourth Amendment to Exhibit 10(c)(1) effective as of January 1, 1993	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(f)(5)
*10(c)(6)	-Fifth Amendment to Exhibit 10(c)(1) effective in part, January 1, 1995, and in part, September 7, 1994	HI's Form 10-K for the year ended December 31, 1994	1-7629	10(f)(6)
*10(c)(7)	-Sixth Amendment to Exhibit 10(c)(1) effective as of August 1, 1995	HI's Form 10-Q for the quarter ended June 30, 1995	1-7629	10(a)
*10(c)(8)	-Seventh Amendment to Exhibit 10(c)(1) effective as of January 1, 1996	HI's Form 10-Q for the quarter ended June 30, 1996	1-7629	10(a)
*10(c)(9)	-Eighth Amendment to Exhibit 10(c)(1) effective as of January 1, 1997	HI's Form 10-Q for the quarter ended June 30, 1997	1-7629	10(a)
*10(c)(10)	-Ninth Amendment to Exhibit 10(c)(1) effective in part, January 1, 1997, and in part, January 1, 1998	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(f)(10)
*10(d)	-Benefit Restoration Plan of HI effective as of June 1, 1985	HI's Form 10-Q for the quarter ended March 31, 1987	1-7629	10(c)
*10(e)	-Benefit Restoration Plan of HI as amended and restated effective as of January 1, 1988	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(g)(2)
*10(f)(1)	-Benefit Restoration Plan of HI, as amended and restated effective as of July 1, 1991	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(g)(3)
*10(f)(2)	-First Amendment to Exhibit 10(f)(1) effective in part, August 6, 1997, in part, September 3, 1997, and in part, October 1, 1997	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(i)(2)

*10(f)(3)	-Third Amendment to Exhibit 10(f)(1) effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.2
*10(g)	-CenterPoint Energy Benefit Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.1
*10(h)(1)	-HI 1995 Section 415 Benefit Restoration Plan effective August 1, 1995	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(h)(1)
*10(h)(2)	-First Amendment to Exhibit 10(h)(1) effective as of August 1, 1995	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(h)(2)
*10(i)	-CenterPoint Energy 1985 Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.1
*10(j)(1)	-Reliant Energy 1994 Long- Term Incentive Compensation Plan, as amended and restated effective January 1, 2001	Reliant Energy's Form 10-Q for the quarter ended June 30, 2002	1-3187	10.6
*10(j)(2)	-First Amendment to Exhibit 10(j)(1), effective December 1, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	10(p)(7)
*10(j)(3)	-Form of Non-Qualified Stock Option Award Notice under Exhibit 10(i)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.6
*10(k)(1)	-Savings Restoration Plan of HI effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1990	1-7629	10(f)
*10(k)(2)	-First Amendment to Exhibit 10(k)(1) effective as of January 1, 1992	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(l)(2)
*10(k)(3)	-Second Amendment to Exhibit 10(k)(1) effective in part, August 6, 1997, and in part, October 1, 1997	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(q)(3)
*10(l)(3)	-Amended and Restated CenterPoint Energy, Inc. 1991 Savings Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.4
*10(m)	-CenterPoint Energy Savings Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.3
*10(n)(1)	-CenterPoint Energy Outside Director Benefits Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.6

*10(n)(2)	-First Amendment to Exhibit 10(n)(1) effective as of January 1, 2004	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2004	1-31447	10.6
*10(n)(3)	-CenterPoint Energy Outside Director Benefits Plan, as amended and restated effective December 31, 2008	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(n)(3)
*10(o)	-CenterPoint Energy Executive Life Insurance Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.5
*10(p)	-Employment and Supplemental Benefits Agreement between HL&P and Hugh Rice Kelly	HI's Form 10-Q for the quarter ended March 31, 1987	1-7629	10(f)
10(q)(1)	-Stockholder's Agreement dated as of July 6, 1995 between Houston Industries Incorporated and Time Warner Inc.	Schedule 13-D dated July 6, 1995	5-19351	2
10(q)(2)	-Amendment to Exhibit 10(q)(1) dated November 18, 1996	HI's Form 10-K for the year ended December 31, 1996	1-7629	10(x)(4)
*10(r)(1)	-Houston Industries Incorporated Executive Deferred Compensation Trust effective as of December 19, 1995	HI's Form 10-K for the year ended December 31, 1995	1-7629	10(7)
*10(r)(2)	-First Amendment to Exhibit 10(r)(1) effective as of August 6, 1997	HI's Form 10-Q for the quarter ended June 30, 1998	1-3187	10
*10(s)	-Letter Agreement dated May 24, 2007 between CenterPoint Energy and Milton Carroll, Non-Executive Chairman of the Board of Directors of CenterPoint Energy	CenterPoint Energy's Form 8-K dated May 31, 2007	1-31447	10.1
*10(t)	-Reliant Energy, Incorporated and Subsidiaries Common Stock Participation Plan for Designated New Employees and Non-Officer Employees, as amended and restated effective January 1, 2001	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(y)(2)
*10(u)(1)	-Long-Term Incentive Plan of CenterPoint Energy, Inc. (amended and restated effective as of May 1, 2004)	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2004	1-31447	10.5
*10(u)(2)	-First Amendment to Exhibit (u)(1), effective January 1, 2007	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2007	1-31447	10.5
*10(u)(3)	-Form of Non-Qualified Stock Option Award Agreement under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.1

*10(u)(4)	-Form of Restricted Stock Award Agreement under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.2
*10(u)(5)	-Form of Performance Share Award under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.3
*10(u)(6)	-Form of Performance Share Award Agreement for 20XX-20XX Performance Cycle under Exhibit 10 (u)(1)	CenterPoint Energy's Form 8-K dated February 22, 2006	1-31447	10.2
*10(u)(7)	-Form of Restricted Stock Award Agreement (With Performance Vesting Requirement) under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated February 21, 2005	1-31447	10.2
*10(u)(8)	-Form of Stock Award Agreement (With Performance Goal) under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated February 22, 2006	1-31447	10.3
*10(u)(9)	-Form of Performance Share Award Agreement for 20XX - 20XX Performance Cycle under Exhibit 10 (u)(1)	CenterPoint Energy's Form 8-K dated February 21, 2007	1-31447	10.1
*10(u)(10)	-Form of Stock Award Agreement (With Performance Goal) under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated February 21, 2007	1-31447	10.2
*10(u)(11)	-Form of Stock Award Agreement (Without Performance Goal) under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated February 21, 2007	1-31447	10.3
*10(u)(12)	-Form of Performance Share Award Agreement for 20XX - 20XX Performance Cycle under Exhibit 10 (u)(1)	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.1
*10(u)(13)	-Form of Stock Award Agreement (With Performance Goal) under Exhibit 10(u)(1)	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.2
10(v)(1)	-Master Separation Agreement entered into as of December 31, 2000 between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.1
10(v)(2)	-First Amendment to Exhibit 10(v)(1) effective as of February 1, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(bb)(5)
10(v)(3)	-Employee Matters Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.5

10(v)(4)	-Retail Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.6
10(v)(5)	-Tax Allocation Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.8
10(w)(1)	-Separation Agreement entered into as of August 31, 2002 between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(1)
10(w)(2)	-Transition Services Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(2)
10(w)(3)	-Tax Allocation Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(3)
*10(x)	-Retention Agreement effective October 15, 2001 between Reliant Energy and David G. Tees	Reliant Energy's Form 10-K for the year ended December 31, 2001	1-3187	10(jj)
*10(y)	-Retention Agreement effective October 15, 2001 between Reliant Energy and Michael A. Reed	Reliant Energy's Form 10-K for the year ended December 31, 2001	1-3187	10(kk)
*10(z)	-Non-Qualified Unfunded Executive Supplemental Income Retirement Plan of Arkla, Inc. effective as of August 1, 1983	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(gg)
*10(aa)(1)	-Deferred Compensation Plan for Directors of Arkla, Inc. effective as of November 10, 1988	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(hh)(1)
*10(aa)(2)	-First Amendment to Exhibit 10(aa)(1) effective as of August 6, 1997	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(hh)(2)
*10(bb)(1)	-CenterPoint Energy, Inc. Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2003	1-31447	10.2
*10(bb)(2)	-First Amendment to Exhibit 10(bb)(1) effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.4
*10(bb)(3)	-CenterPoint Energy 2005 Deferred Compensation Plan, effective January 1, 2008	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.3

*10(bb)(4)	-Amended and Restated CenterPoint Energy 2005 Deferred Compensation Plan, effective January 1, 2009	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.1
*10(cc)(1)	-CenterPoint Energy Short Term Incentive Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.3
*10(cc)(2)	-Second Amendment to Exhibit 10(cc)(1)	CenterPoint Energy's Form 8-K dated December 10, 2009	1-31447	10.1
*10(dd)	-CenterPoint Energy Stock Plan for Outside Directors, as amended and restated effective May 7, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	10(ll)
10(ee)	-City of Houston Franchise Ordinance	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2005	1-31447	10.1
10(ff)	-Letter Agreement dated March 16, 2006 between CenterPoint Energy and John T. Cater	CenterPoint Energy's Form 10-Q for the quarter ended March 30, 2006	1-31447	10
10(gg)(1)	-Amended and Restated HL&P Executive Incentive Compensation Plan effective as of January 1, 1985	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.2
10(gg)(2)	-First Amendment to Exhibit 10(gg)(1) effective as of January 1, 2008	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.3
*10(hh)(1)	-Executive Benefits Agreement by and between HL&P and Thomas R. Standish effective August 20, 1993	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(hh)(1)
*10(hh)(2)	-First Amendment to Exhibit 10(hh)(1) effective as of December 31, 2008	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(hh)(2)
*10(ii)(1)	-Executive Benefits Agreement by and between HL&P and David M. McClanahan effective August 24, 1993	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(ii)(1)
*10(ii)(2)	-First Amendment to Exhibit 10(ii)(1) effective as of December 31, 2008	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(ii)(2)
*10(jj)(1)	-Executive Benefits Agreement by and between HL&P and Joseph B. McGoldrick effective August 30, 1993	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(jj)(1)
*10(jj)(2)	-First Amendment to Exhibit 10(jj)(1) effective as of December 31, 2008	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(jj)(2)

*10(kk)(1)	-CenterPoint Energy, Inc. 2009 Long Term Incentive Plan	CenterPoint Energy's Schedule 14A dated March 13, 2009	1-31447	A
†*10(kk)(2)	-Form of Qualified Performance Award Agreement for 20XX - 20XX Performance Cycle under Exhibit 10(kk)(1)			
†*10(kk)(3)	-Form of Restricted Stock Unit Award Agreement (With Performance Goal) under Exhibit 10(kk)(1)			
†10(ll)	-Summary of non-employee director compensation			
†10(mm)	-Summary of named executive officer compensation			
10(nn)	-Form of Executive Officer Change in Control Agreement	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(nn)
10(oo)	-Form of Corporate Officer Change in Control Agreement	CenterPoint Energy's Form 10-K for the year ended December 31, 2008	1-31447	10(oo)
†12	-Computation of Ratio of Earnings to Fixed Charges			
†21	-Subsidiaries of CenterPoint Energy			
†23	-Consent of Deloitte & Touche LLP			
†31.1	-Rule 13a-14(a)/15d-14(a) Certification of David M. McClanahan			
†31.2	-Rule 13a-14(a)/15d-14(a) Certification of Gary L. Whitlock			
†32.1	-Section 1350 Certification of David M. McClanahan			
†32.2	-Section 1350 Certification of Gary L. Whitlock			
†101.INS	-XBRL Instance Document (1)			
†101.SCH	-XBRL Taxonomy Extension Schema Document (1)			
†101.CAL	-XBRL Taxonomy Extension Calculation Linkbase Document (1)			

†101.DEF	-XBRL Taxonomy Extension Definition Linkbase Document (1)
†101.LAB	-XBRL Taxonomy Extension Labels Linkbase Document (1)
†101.PRE	-XBRL Taxonomy Extension Presentation Linkbase Document (1)

(1) Furnished, not filed.

Exhibit 10(kk)(2)

CENTERPOINT ENERGY, INC.
2009 LONG TERM INCENTIVE PLAN

QUALIFIED PERFORMANCE AWARD AGREEMENT
JANUARY 1, 20XX – DECEMBER 31, 20XX PERFORMANCE CYCLE

Pursuant to this Qualified Performance Award Agreement (the "Award Agreement"), CenterPoint Energy, Inc. (the "Company") hereby grants to the Participant, an employee of the Company, these target shares of Common Stock (the "Target Shares"), such number of shares being subject to adjustment as provided in Section 14 of the CenterPoint Energy, Inc. 2009 Long Term Incentive Plan (the "Plan"), conditioned upon the Company's achievement of the Performance Goals over the course of the 20XX – 20XX Performance Cycle, and subject to the following terms and conditions:

1. Relationship to the Plan. This grant of Target Shares is subject to all of the terms, conditions and provisions of the Plan in effect on the date hereof and administrative interpretations thereunder, if any, adopted by the Committee. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, it is hereby acknowledged and agreed that the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant herein also include the heirs or other legal representatives of the Participant.

2. Definitions. Except as defined herein, capitalized terms shall have the same meanings ascribed to them under the Plan. For purposes of this Award Agreement:

"Achievement Percentage" means the percentage of achievement determined by the Committee after the end of the Performance Cycle in accordance with Section 4 that reflects the extent to which the Company achieved the Performance Goals during the Performance Cycle.

"Change in Control Closing Date" means the date a Change in Control is consummated during the Performance Cycle.

"Disability" means that the Participant is (i) eligible for and in receipt of benefits under the Company's long-term disability plan and (ii) not eligible for Retirement.

"Employment" means employment with the Company or any of its Subsidiaries.

"Performance Cycle" means the period beginning on January 1, 20XX and ending on December 31, 20XX.

"Retirement" means a Separation from Service on or after the attainment of age 55 and with at least five years of service with the Company; *provided, however* , that such Separation from Service is not by the Company for Cause. For purposes of this Award Agreement, "Cause" means the Participant's (a) gross negligence in the performance of his or her duties, (b) intentional and continued failure to perform his or her duties, (c) intentional engagement in conduct which is materially injurious to the Company or its Subsidiaries (monetarily or otherwise) or (d) conviction of a felony or a misdemeanor involving moral turpitude. For this purpose, an act or failure to act on the part of the Participant will be deemed "intentional" only if done or omitted to be done by the Participant not in good faith and without reasonable belief that his or her action or omission was in the best interest of the Company, and no act or failure to act on the part of the Participant will be deemed "intentional" if it was due primarily to an error in judgment or negligence.

"Separation from Service" means a separation from service with the Company or any of its Subsidiaries within the meaning of Treasury Regulation § 1.409A-1(h) (or any successor regulation).

"Target Shares" means the actual number of shares originally granted to the Participant pursuant to this Award Agreement, with such number of shares to be actually awarded to the Participant at the close of the Performance Cycle if the Company attains an Achievement Percentage of 100% for the Performance Goals associated with such Target Shares.

"Vested Shares" means the shares of Common Stock actually awarded to the Participant following the Participant's satisfaction of the vesting provisions of Section 5 and, if applicable, the determination by the Committee of the extent to which the Company has achieved the Performance Goals for the Performance Cycle pursuant to Section 4.

3. Establishment of Award Account. The grant of Target Shares pursuant to this Award Agreement shall be implemented by a credit to a bookkeeping account maintained by the Company evidencing the accrual in favor of the Participant of the unfunded and unsecured right to receive shares of Common Stock of the Company, which right shall be subject to the terms, conditions and restrictions set forth in the Plan and to the further terms, conditions and restrictions set forth in this Award Agreement. Except as otherwise provided in this Award Agreement, the Target Shares of Common Stock credited to the Participant’s bookkeeping account may not be sold, assigned, transferred, pledged or otherwise encumbered until the Participant has been registered as a holder of shares of Common Stock on the records of the Company as provided in Section 6 or 7 of this Award Agreement.

4. Award Opportunity.

(a) The Performance Goals established for the Performance Cycle are attached hereto and made a part hereof for all purposes. Except as otherwise provided in Section 5(b)(ii) and Section 6, the Vested Shares awarded to the Participant shall be the product of the number of Target Shares and the Achievement Percentage that is based upon the Committee's determination of whether and to what extent the Performance Goals have been achieved during the Performance Cycle.

(b) No later than 60 days after the close of the Performance Cycle, the Committee shall determine the extent to which each Performance Goal has been achieved. If the Company has performed at or above the threshold level of achievement for a Performance Goal, the Achievement Percentage shall be between 50% and 150%, with a target level of achievement resulting in an Achievement Percentage of 100%. In no event shall the Achievement Percentage exceed 150%. The combined level of achievement is the sum of the weighted achievements of the Performance Goals as approved by the Committee. Upon completing its determination of the level at which the Performance Goals have been achieved, the Committee shall notify the Participant, in the form and manner as determined by the Committee, of the number of Vested Shares that will be issued to the Participant pursuant to Section 7.

5. Vesting of Shares.

(a) Unless earlier forfeited in accordance with Section 5(b)(i) or unless earlier vested in accordance with Section 5(b)(ii) or Section 6, the Participant's right to receive shares pursuant to this Award Agreement, if any, shall vest on the date the Committee determines that each Performance Goal has been met (as provided in Section 4). As soon as administratively practicable, but in no event later than 70 days, after the close of the Performance Cycle, the Committee shall notify the Participant as required by Section 4 of the level at which the Performance Goals established for the Performance Cycle have been achieved.

(b) If the Participant's Separation from Service date occurs prior to the close of the Performance Cycle or the occurrence of a Change in Control, then the applicable of the following clauses shall apply with respect to the Target Shares subject to this Award Agreement:

(i) Forfeiture of Entire Award. If the Participant's Employment is terminated, such that the Participant has a Separation from Service, by the Company or any of its Subsidiaries or by the Participant for any reason other than due to death, Disability or Retirement, then the Participant's right to receive any Target Shares shall be forfeited in its entirety as of the date of such Separation from Service.

(ii) Death or Disability. If the Participant's Employment is terminated due to death or Disability, the Participant's right to receive the Target Shares shall vest on the date of such Separation from Service in the proportion of the number of days elapsed in the Performance Cycle as of the date of Separation from Service by the total number of days in the Performance Cycle. The Participant's right to receive any additional shares pursuant to this Award Agreement shall be forfeited at such time.

(iii) Retirement. If the Participant's Employment is terminated due to Retirement, the Participant's right to receive shares pursuant to this Award Agreement, if any, shall vest on the date the Committee determines that each Performance Goal has been met (as provided in Section 4) in a pro-rata amount determined by multiplying (1) the number of Vested Shares awarded to the Participant based upon the Committee's determination of achievement of Performance Goals as provided in Section 4, by (2) a fraction, the numerator of which is the number of days elapsed in the Performance Cycle as of the date of the Participant's Separation from Service, and the denominator of which is the total number of days in the Performance Cycle. The Participant's right to receive any additional shares pursuant to this Award Agreement shall be forfeited at such time.

(c) In accordance with the provisions of this Section 5, the Vested Shares shall be distributed as provided in Section 7 hereof.

6. Distribution Upon a Change in Control. Notwithstanding anything herein to the contrary and without regard to the Performance Goals, if there is a Change in Control during the Performance Cycle, upon the Change in Control Closing Date, the Participant's right to receive the Target Shares shall vest and be settled by the distribution to the Participant of:

(a) shares of Common Stock equal to the Target Shares; *plus*

(b) shares of Common Stock (rounded up to the nearest whole share) having a Fair Market Value equal to the amount of dividends that would have been declared on the number of such shares determined under clause (a) above during the period commencing at the beginning of the Performance Cycle and ending on the date immediately preceding the Change in Control Closing Date.

In lieu of the foregoing distribution in shares, the Committee, in its sole discretion, may direct that such distribution be made to the Participant in a lump cash payment equal to:

(x) the product of (i) the Fair Market Value per share of Common Stock on the date immediately preceding the Change in Control Closing Date and (ii) the Target Shares; *plus*

(y) the amount of dividends that would have been declared on the number of shares of Common Stock determined under clause (a) above during the period commencing at the beginning of the Performance Cycle and ending on the date immediately preceding the Change in Control Closing Date.

Such distribution, whether in the form of shares of Common Stock or, if directed by the Committee, in cash, shall be made to the Participant no later than the 70th day after the Change in Control Closing Date, and shall satisfy the rights of the Participant and the obligations of the Company under this Award Agreement in full. In the event a Change in Control occurs after the Participant has had a Separation from Service due to Retirement, the Target Shares such Participant shall receive under this Section 6 shall be pro-rated based on the number of days that elapsed in the Performance Cycle as of his Separation from Service date over the total number of days in the Performance Cycle.

7. Distribution of Vested Shares.

(a) If the Participant's right to receive shares pursuant to this Award Agreement has vested pursuant to Section 5(a) or Section 5(b)(iii), a number of shares of Common Stock equal to the number of Vested Shares shall be registered in the name of the Participant and shall be delivered to the Participant no later than March 15th of the calendar year following the calendar year in which occurs the last day of the Performance Cycle.

(b) If the Participant's right to receive shares pursuant to this Award Agreement has vested pursuant to Section 5(b)(ii), a number of shares of Common Stock equal to the number of Vested Shares shall be registered in the name of the Participant (or his or her estate, if applicable) and shall be delivered to the Participant (or his or her estate, if applicable) not later than the 70th day after the Participant's Separation from Service date.

(c) The Company shall have the right to withhold applicable taxes from any such distribution of Vested Shares or from other compensation payable to the Participant at the time of such vesting and delivery pursuant to Section 11 of the Plan (but subject to compliance with the requirements of Section 409A of the Internal Revenue Code ("Section 409A"), if applicable).

(d) Upon delivery of the Vested Shares pursuant to Section 7(a) or 7(b) above, the Participant shall also be entitled to receive a cash payment equal to the sum of all dividends, if any, declared on the Vested Shares after the commencement of the Performance Cycle but prior to the date the Vested Shares are delivered to the Participant.

8. Confidentiality. The Participant agrees that the terms of this Award Agreement are confidential and that any disclosure to anyone for any purpose whatsoever (save and except disclosure to financial institutions as part of a financial statement, financial, tax and legal advisors, or as required by law) by the Participant or his or her agents, representatives, heirs, children, spouse, employees or spokespersons shall be a breach of this Award Agreement and the Company may elect to revoke the grant made hereunder, seek damages, plus interest and reasonable attorneys' fees, and take any other lawful actions to enforce this Award Agreement.

9. Notices. For purposes of this Award Agreement, notices to the Company shall be deemed to have been duly given upon receipt of written notice by the Corporate Secretary of CenterPoint Energy, Inc., 1111 Louisiana, Houston, Texas 77002, or to such other address as the Company may furnish to the Participant.

Notices to the Participant shall be deemed effectively delivered or given upon personal, electronic, or postal delivery of written notice to the Participant, the place of Employment of the Participant, the address on record for the Participant at the human resources department of the Company, or such other address as the Participant hereafter designates by written notice to the Company.

10. Shareholder Rights. The Participant shall have no rights of a shareholder with respect to the Target Shares, unless and until the Participant is registered as the holder of shares of Common Stock.

11. Successors and Assigns. This Award Agreement shall bind and inure to the benefit of and be enforceable by the Participant, the Company and their respective permitted successors and assigns except as expressly prohibited herein and in the Plan. Notwithstanding anything herein or in the Plan to the contrary, the Target Shares are transferable by the Participant to Immediate Family Members, Immediate Family Member trusts, and Immediate Family Member partnerships pursuant to Section 13 of the Plan.

12. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Company or any Subsidiary or any successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

13. Waiver. Failure of either party to demand strict compliance with any of the terms or conditions hereof shall not be deemed a waiver of such term or condition, nor shall any waiver by either party of any right hereunder at any one time or more times be deemed a waiver of such right at any other time or times. No term or condition hereof shall be deemed to have been waived except by written instrument.

14. Exclusion from Section 409A. At all times prior to the date that the Committee determines that each Performance Goal has been met (following the last date of the Performance Cycle) or, if applicable under Section 6 or 7(b), the Change in Control Closing Date or the Participant's Separation from Service, respectively, the benefit payable under this Award

Agreement is subject to a substantial risk of forfeiture within the meaning of Treasury Regulation § 1.409A-1(d) (or any successor regulation) . Accordingly, t his Award is not subject to Section 409A under the short term deferral exclusion, and this Award Agreement shall be interpreted and administered consistent therewith.

15. Compliance with Recoupment Policy. Any amounts payable, paid, or distributed under this Award Agreement are subject to the recoupment policy of the Company as in effect from time to time.

16. Modification of Award Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Company.

Exhibit 10(kk)(3)

CENTERPOINT ENERGY, INC.
2009 LONG TERM INCENTIVE PLAN

RESTRICTED STOCK UNIT AWARD AGREEMENT
(With Performance Goal)

Pursuant to this Restricted Stock Unit Award Agreement ("Award Agreement"), CenterPoint Energy, Inc. (the "Company") hereby grants to the Participant, an employee of the Company, on the Award Date, a restricted stock unit award of these units of Common Stock of the Company (the "RSU Award"), pursuant to the CenterPoint Energy, Inc. 2009 Long Term Incentive Plan (the "Plan"), which is a qualified Performance Award under the Plan, conditioned upon the Company's achievement of the Performance Goals established by the Committee over the course of the Vesting Period, and subject to the terms, conditions and restrictions described in the Plan and as follows:

1. Relationship to the Plan; Definitions. This RSU Award is subject to all of the terms, conditions and provisions of the Plan in effect on the date hereof and administrative interpretations thereunder, if any, adopted by the Committee. Except as defined herein, capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, it is hereby acknowledged and agreed that the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant herein also include the heirs or other legal representatives of the Participant. For purposes of this Award Agreement:

"Award Date" means the date this RSU Award is granted to the Participant.

"Change in Control Closing Date" means the date a Change in Control (as defined in the Plan) is consummated during the Vesting Period.

"Change in Control Payment Date" means the following:

(i) If the Participant *is not* Retirement Eligible, then the Change in Control Payment Date shall be not later than the 70th day after the Change in Control Closing Date (regardless of whether or not the Participant is a Specified Employee); and

(ii) If the Participant *is* Retirement Eligible and the Change in Control is a Section 409A Change in Control, then the Change in Control Payment Date shall be not later than the 70th day after the Change in Control Closing Date (regardless of whether or not the Participant is a Specified Employee); and

(iii) If the Participant *is* Retirement Eligible, the Change in Control is not a Section 409A Change in Control and the Participant is not a Specified

Employee, then the Change in Control Payment Date shall be not later than the 70th day after the earlier of:

(1) the Vesting Date; or

(2) the Termination Date.

(iv) If the Participant *is* Retirement Eligible, the Change in Control is not a Section 409A Change in Control and the Participant is a Specified Employee, then the Change in Control Payment Date shall be as follows:

(1) if (x) the Participant is in continuous Employment from the Change in Control Closing Date until and including the Vesting Date or (y) the Participant's death occurs prior to the Vesting Date, then the Change in Control Payment Date shall be not later than the 70th day after the earlier of:

(a) the Vesting Date; or

(b) the date of the Participant's death; or

(2) if the Participant's Employment terminates following the Change in Control Closing Date, other than due to death, but prior to the Vesting Date, then the Change in Control Payment Date shall be the earlier of:

(a) the second business day following the end of the six-month period commencing on the Participant's Termination Date; or

(b) the date of the Participant's death, if death occurs during such six-month period.

"Disability" means that the Participant is both eligible for and in receipt of benefits under the Company's long-term disability plan.

"Employment" means employment with the Company or any of its Subsidiaries.

"Performance Goals" means the standards established by the Committee to determine in whole or in part whether the units of Common Stock under the RSU Award shall vest, which are attached hereto and made a part hereof for all purposes.

"Retirement" means a Separation from Service (i) on or after attainment of age 55 and (ii) with at least five years of Employment; *provided, however* , that such Separation from Service is not by the Company for Cause. For purposes of this Award Agreement, "Cause" means the Participant's (a) gross negligence in the performance of his or her duties, (b) intentional and continued failure to perform his or her duties, (c) intentional engagement in conduct which is materially injurious to the Company or its Subsidiaries (monetarily or otherwise) or (d) conviction of a felony or a misdemeanor involving moral turpitude. For this purpose, an act or failure to act on the part of the Participant will be deemed "intentional" only if done or omitted to be done by the Participant not in good faith and without reasonable belief that his or her action or omission was in the best interest of the Company, and no act or failure to act on the part of the Participant will be deemed "intentional" if it was due primarily to an error in judgment or negligence.

"Retirement Eligible" means the Participant (i) is or will be age 55 or older and (ii) has or will have at least five years of Employment, on or after the Award Date but prior to the calendar year in which the Vesting Date occurs.

"Section 409A" means Code Section 409A and the Treasury regulations and guidance issued thereunder.

"Section 409A Change in Control" means a Change in Control that satisfies the requirements of a change in control for purposes of Code Section 409A(a)(2)(A)(v) and the Treasury regulations and guidance issued thereunder.

"Separation from Service" means a separation from service with the Company or any of its Subsidiaries within the meaning of Treasury Regulation § 1.409A-1(h) (or any successor regulation).

"Specified Employee" has the meaning of that term under Code Section 409A(a)(2)(B)(i) and the Treasury regulations and guidance issued thereunder.

"Termination Date" means the date of the Participant's Separation from Service.

"Vesting Date" means **[_________, 20XX]** .

"Vesting Period" means the period commencing on the Award Date and ending on the Vesting Date.

2. Establishment of RSU Award Account. The grant of units of Common Stock of the Company pursuant to this Award Agreement shall be implemented by a credit to a bookkeeping account maintained by the Company evidencing the accrual in favor of the Participant of the unfunded and unsecured right to receive such units of Common Stock, which right shall be subject to the terms, conditions and restrictions set forth in the Plan and to the further terms, conditions and restrictions set forth in this Award Agreement. Except as otherwise provided in Section 10 of this Award Agreement, the units of Common Stock credited to the Participant's bookkeeping account may not be sold, assigned, transferred, pledged or otherwise encumbered until the Participant has been registered as the holder of shares of Common Stock on the records of the Company, as provided in Sections 4, 5 or 6 of this Award Agreement.

3. Vesting of RSU Award. Unless earlier (a) vested or forfeited pursuant to this Section 3 or Section 4 below or (b) vested upon the occurrence of a Change in Control pursuant to Section 5 below, the Participant's right to receive shares of Common Stock (if any) under this Award Agreement shall vest on the Vesting Date. No later than 60 days after the Vesting Date, the Committee shall determine the extent to which the Performance Goal has been achieved. Upon completing its determination of the level at which the Performance Goal has been achieved, the Committee shall notify the Participant, in the form and manner as determined by the Committee, of the number of shares of Common Stock (if any) under this Award Agreement that will be issued to the Participant pursuant to Section 6. Except as provided in Sections 4 and 5 below, the Participant must be in continuous Employment during the Vesting Period in order for the RSU Award to vest; otherwise, all such units shall be forfeited as of the Participant's Termination Date.

4. Effect of Separation from Service; Timing of Distribution.

(a) Separation from Service Prior to the Vesting Date or Change in Control . Notwithstanding Section 3 above, if prior to (i) the Vesting Date or (ii) the occurrence of a Change in Control, the Participant's Separation from Service occurs due to Retirement, death or Disability, then:

(1) *Retirement* . In the event of Retirement, the Participant shall vest in the right to receive a number, if any, of the shares of Common Stock (rounded up to the nearest whole share) determined by multiplying (x) the total number of units of Common Stock subject to this Award Agreement based upon the Committee's determination of the achievement of the Performance Goal after the end of the Vesting Period, as provided in Section 3, by (y) a fraction, the numerator of which is the number of days that have elapsed from the Award Date to the Participant's Termination Date, and the denominator of which is the total number of days in the Vesting Period; or

(2) *Death or Disability* . In the event of the Participant's death or Separation from Service due to Disability, without regard to the Performance Goals, the Participant shall vest in the right to receive a number of the shares of Common Stock (rounded up to the nearest whole share) determined by multiplying (x) the total number of units of Common Stock granted subject to this Award Agreement by (y) a fraction, the numerator of which is the number of days that have elapsed from the Award Date to the Participant's Termination Date, and the denominator of which is the total number of days in the Vesting Period.

(b) Timing of Distribution .

(1) *Retirement* . If the Participant is entitled to a benefit pursuant to Section 4(a)(1) hereof, a number of shares of Common Stock equal to the number of vested shares of Common Stock subject to this Award Agreement (as determined by the Committee in accordance with Section 3 and Section 4(a)(1), if any) shall be registered in the name of the Participant and delivered to the Participant not later than the 70th day after the Vesting Date.

(2) *Death* . If the Participant is entitled to a benefit pursuant to Section 4(a)(2) hereof due to the Participant's death, the number of shares of Common Stock determined in accordance with Section 4(a)(2) shall be registered in the name of the Participant's estate and delivered to the Participant's estate as soon as practicable but not later than the 70th day after the date of the Participant's death.

(3) *Disability* .

(A) Specified Employee and Retirement Eligible . If the Participant (i) is entitled to a benefit pursuant to Section 4(a)(2) hereof due to the Participant's Separation from Service due to Disability, (ii) is a Specified Employee, and (iii) is Retirement Eligible, the number of shares of Common Stock determined in accordance with Section 4(a)(2) shall be registered in the name of the Participant and delivered to the Participant on the date that is the earlier of (x) the second business day following the end of the six-month period commencing on the Participant's Termination Date or (y) the Participant's date of death, if death occurs during such six-month period.

(B) All Other Participants . Except as provided in Section 4(b)(3)(A), if the Participant is entitled to a benefit pursuant to Section 4(a)(2) hereof due to the Participant's Separation from Service due to Disability, the number of shares of Common Stock determined in accordance with Section 4(a)(2) shall be registered in the name of the Participant and delivered to the Participant as soon as practicable but not later than the 70th day after the date of the Participant's Termination Date.

(c) Dividend Equivalents . Upon the date of delivery of shares of Common Stock under this Section 4, the Participant shall also be entitled to receive Dividend Equivalents for the period from the Award Date to the date such vested shares of Common Stock are distributed to the Participant (in accordance with the requirements of Section 409A, to the extent applicable).

5. Distribution Upon a Change in Control. Notwithstanding any provision of this Award Agreement to the contrary, if during the Participant's Employment and prior to the end of the Vesting Period or an accelerated vesting event under Section 4 above there is a Change in Control of the Company, then, upon the Change in Control Closing Date and without regard to the Performance Goal, the Participant's right to receive the unvested units of Common Stock subject to this Award Agreement shall be vested and settled by a distribution, on the Change in Control Payment Date, to the Participant of:

(a) The number of units of Common Stock subject to this Award Agreement not previously vested or forfeited pursuant to Sections 3 or 4 above, *plus*

(b) Dividend Equivalents in the form of shares of Common Stock (rounded up to the nearest whole share) for the period commencing on the Award Date and ending on the date immediately preceding the Change in Control Closing Date;

with such shares of Common Stock registered in the name of the Participant and delivered to the Participant. In lieu of the foregoing distribution in shares, the Committee, in its sole discretion, may direct that such distribution be made to the Participant in a lump sum cash payment equal to:

(x) The product of (i) the Fair Market Value per share of Common Stock on the date immediately preceding the Change in Control Closing Date and (ii) the number of units of Common Stock subject to this Award Agreement not previously vested or forfeited pursuant to Sections 3 or 4 above, *plus*

(y) Dividend Equivalents for the period commencing on the Award Date and ending on the date immediately preceding the Change in Control Closing Date;

with such cash payment to be made on the Change in Control Payment Date. Such distribution under this Section 5, whether in the form of shares of Common Stock or, if directed by the Committee, in cash, shall satisfy the rights of the Participant and the obligations of the Company under this Award Agreement in full.

6. Payment of RSU Award Under Section 3. Upon the vesting of the Participant's right to receive the shares of Common Stock pursuant to Section 3 under this Award Agreement, a number of shares of Common Stock equal to the number of vested shares of Common Stock subject to this Award Agreement (as determined by the Committee in accordance with Section 3, if any) shall be registered in the name of the Participant and delivered to the Participant not later than the 70th day after the Vesting Date. Moreover, upon the date of delivery of shares of Common Stock, the Participant shall also be entitled to receive Dividend Equivalents for the period commencing on the Award Date and ending on the date such vested shares of Common Stock are distributed to the Participant (in accordance with the requirements of Section 409A, to the extent applicable).

7. Confidentiality. The Participant agrees that the terms of this Award Agreement are confidential and that any disclosure to anyone for any purpose whatsoever (save and except disclosure to financial institutions as part of a financial statement, financial, tax and legal advisors, or as required by law) by the Participant or his or her agents, representatives, heirs, children, spouse, employees or spokespersons shall be a breach of this Award Agreement and the Company may elect to revoke the grant made hereunder, seek damages, plus interest and reasonable attorneys' fees, and take any other lawful actions to enforce this Award Agreement.

8. Notices. For purposes of this Award Agreement, notices to the Company shall be deemed to have been duly given upon receipt of written notice by the Corporate Secretary of CenterPoint Energy, Inc., 1111 Louisiana, Houston, Texas 77002, or to such other address as the Company may furnish to the Participant.

Notices to the Participant shall be deemed effectively delivered or given upon personal, electronic, or postal delivery of written notice to the Participant, the place of Employment of the Participant, the address on record for the Participant at the human resources department of the Company, or such other address as the Participant hereafter designates by written notice to the Company.

9. Shareholder Rights. The Participant shall have no rights of a shareholder with respect to the units of Common Stock subject to this Award Agreement, unless and until the Participant is registered as the holder of such shares of Common Stock.

10. Successors and Assigns. This Award Agreement shall bind and inure to the benefit of and be enforceable by the Participant, the Company and their respective permitted successors and assigns except as expressly prohibited herein and in the Plan. Notwithstanding anything herein or in the Plan to the contrary, the units of Common Stock are transferable by the Participant to Immediate Family Members, Immediate Family Member trusts, and Immediate Family Member partnerships pursuant to Section 13 of the Plan.

11. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Company or any Subsidiary, or any successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

12. Waiver. Failure of either party to demand strict compliance with any of the terms or conditions hereof shall not be deemed a waiver of such term or condition, nor shall any waiver by either party of any right hereunder at any one time or more times be deemed a waiver of such right at any other time or times. No term or condition hereof shall be deemed to have been waived except by written instrument.

13. Compliance with Section 409A. It is the intent of the Company and the Participant that the provisions of the Plan and this Award Agreement comply with Section 409A and will be interpreted and administered consistent therewith. Accordingly, (i) no adjustment to the RSU Award pursuant to Section 14 of the Plan and (ii) no substitutions of the benefits under this Award Agreement, in each case, shall be made in a manner that results in noncompliance with the requirements of Section 409A, to the extent applicable. The foregoing notwithstanding, if the Participant is not Retirement Eligible, then at all times prior to the payment date, the benefit payable under this Award Agreement is subject to a substantial risk of forfeiture within the meaning of Treasury Regulation § 1.409A-1(d) (or any successor regulation) and, accordingly, with respect to such Participant, this RSU Award is not subject to Section 409A under the short term deferral exclusion, and this Award Agreement shall be interpreted and administered consistent therewith.

14. Withholding. The Company shall have the right to withhold applicable taxes from any distribution of the Common Stock (including, but not limited to, Dividend Equivalents) or from other cash compensation payable to the Participant at the time of such vesting and delivery pursuant to Section 11 of the Plan (but subject to compliance with the requirements of Section 409A, if applicable).

15. Compliance with Recoupment Policy. Any amounts payable, paid, or distributed under this Award Agreement are subject to the recoupment policy of the Company as in effect from time to time.

16. Modification of Award Agreement. Any modification of this Award Agreement is subject to Section 13 hereof and shall be binding only if evidenced in writing and signed by an authorized representative of the Company.

Exhibit 10(ll)

CenterPoint Energy, Inc.
Summary of Non-Employee Director Compensation

The following is a summary of compensation paid to the non-employee directors of CenterPoint Energy, Inc. (the "Company") effective April 24, 2008. For additional information regarding the compensation of the non-employee directors, please read the definitive proxy statement relating to the Company's 2010 annual meeting of shareholders to be filed pursuant to Regulation 14A.

- Annual retainer fee of $50,000 for Board membership;
- Fee of $2,000 for each Board or Committee meeting attended;
- Supplemental annual retainer of $15,000 for serving as a chairman of the Audit Committee;
- Supplemental annual retainer of $10,000 for serving as a chairman of the Compensation Committee; and
- Supplemental annual retainer of $5,000 for serving as a chairman of any other Board committee.

The Chairman receives the compensation payable to other non-employee directors plus supplemental compensation pursuant to a letter agreement with the Company incorporated by reference to Exhibit 10(p) to the Company's Annual Report on Form 10-K for the year ended December 31, 2007.

Stock Grants. Each non-employee director may also receive an annual grant of up to 5,000 shares of CenterPoint Energy common stock which vest in one-third increments on the first, second and third anniversaries of the grant date. Upon the initial nomination to the Board, in addition to the annual grant, a non-employee director may be granted a one-time grant of up to 5,000 shares of CenterPoint Energy common stock.

Deferred Compensation Plan. Directors may elect each year to defer all or part of their annual retainer fees, including committee chairman fees, and meeting fees. Directors participating in these plans may elect to receive distributions of their deferred compensation and interest in three ways: (i) an early distribution of either 50% or 100% of their account balance in any year that is at least four years from the year of deferral up to the year in which they reach age 70, (ii) a lump sum distribution payable in the year after they reach age 70 or upon leaving the Board of Directors, whichever is later, or (iii) 15 annual installments beginning on the first of the month coincident with or next following age 70 or upon leaving the Board of Directors, whichever is later.

Director Benefits Plan. Non-employee directors elected to the Board before 2004 participatd in a director benefits plan under which a director who served at least one full year would receive an annual cash amount equal to the annual retainer (excluding any supplemental retainer) in effect when the director terminated service. In accordance with the transition rules under Section 409A of the Internal Revenue Code, the Board amended the plan to freeze future benefit accruals under the plan effective December 31, 2008 and to provide commencement of payments as of February 1, 2009. Each active director participating in this plan was given the opportunity to make a one-time irrevocable election by December 31, 2008 as to the payment form. Each active director elected a lump sum payment; therefore, all accrued benefits under the plan were paid on February 1, 2009.

Executive Life Insurance Plan. Non-employee directors who were elected to the Board before 2001 participate in CenterPoint Energy's executive life insurance plan. This plan provides endorsement split-dollar life insurance with a death benefit of $180,000 with coverage continuing after the director's termination of service at age 65 or later. Directors elected to the Board after 2000 may not participate in this plan.

Exhibit 10(mm)

CenterPoint Energy, Inc.
Summary of Named Executive Officer Compensation

The following is a summary of compensation paid to the named executive officers of CenterPoint Energy, Inc. (the "Company"). For additional information regarding the compensation of the named executive officers, please read the definitive proxy statement relating to the Company's 2010 annual meeting of shareholders to be filed pursuant to Regulation 14A.

Base Salary. The following table sets forth the annual base salary of the Company's named executive officers effective April 1, 2010:

Name and Position	Base Salary
David M. McClanahan President and Chief Executive Officer	$ 1,100,000
Gary L. Whitlock Executive Vice President and Chief Financial Officer	$ 525,000
Scott E. Rozzell Executive Vice President, General Counsel and Corporate Secretary	$ 490,000
Thomas R. Standish Senior Vice President and Group President — Regulated Operations	$ 472,000
C. Gregory Harper Senior Vice President and Group President, Pipelines and Field Services	$ 355,000

Short Term Incentive Plan. Annual bonuses are paid to the Company's named executive officers pursuant to the Company's short term incentive plan, which provides for cash bonuses based on the achievement of certain performance objectives approved in accordance with the terms of the plan at the commencement of the year. Information regarding awards to the Company's named executive officers under the short term incentive plan is provided in definitive proxy statements relating to the Company's annual meeting of shareholders.

Long Term Incentive Plan . Under the Company's long term incentive plan, the Company's named executive officers may receive grants of (i) stock option awards, (ii) performance share awards, (iii) performance unit awards and/or (iv) stock awards. The current forms of the applicable award agreements pursuant to the Company's long term incentive plan are included as exhibits hereto.

Exhibit 12

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Millions of Dollars)

	2005	2006	2007 (1)	2008 (1)	2009 (1)
Income from continuing operations	$ 220	$ 427	$ 395	$ 446	$ 372
Equity in earnings of unconsolidated affiliates	(6)	(6)	(16)	(51)	(15)
Income taxes for continuing operations	150	59	193	277	176
Capitalized interest	(4)	(10)	(22)	(12)	(4)
	360	470	550	660	529
Fixed charges, as defined:					
Interest	718	608	632	604	644
Capitalized interest	4	10	22	12	4
Interest component of rentals charged to operating expense	12	19	16	15	12
Total fixed charges	734	637	670	631	660
Earnings, as defined	$ 1,094	$ 1,107	$ 1,220	$ 1,291	$ 1,189
Ratio of earnings to fixed charges	1.49	1.74	1.82	2.05	1.80

(1) Excluded from the computation of fixed charges for the years ended December 31, 2007, 2008 and 2009 is interest income of $4 million, interest expense of $9 million and interest income of $3 million, respectively, which is included in income tax expense.

Exhibit 21

SIGNIFICANT SUBSIDIARIES OF CENTERPOINT ENERGY, INC.

The following subsidiaries are deemed "significant subsidiaries" pursuant to Item 601(b) (21) of Regulation S-K:

Utility Holding, LLC, a Delaware limited liability company and a direct wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Investment Management, Inc., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Resources Corp., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Houston Electric, LLC, a Texas limited liability company and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Services, Inc., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Gas Transmission Company, a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Field Services, Inc., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

(1) Pursuant to Item 601(b) (21) of Regulation S-K, registrant has omitted the names of subsidiaries, which considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" (as defined under Rule 1-02(w) of Regulation S-X) as of December 31, 2009.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-155475, 333-153916 and 333-114543 on Form S-3; Registration Statement Nos. 333-159586, 333-105773, 333-149757, 333-101202, as amended, and 333-115976, as amended, on Form S-8; Post-Effective Amendment No. 1 to Registration Statement No. 333-33303-99 on Form S-3; Post Effective Amendment No. 1 to Registration Statement Nos. 333-32413-99, 333-49333-99, 333-38188-99, 333-60260-99 and 333-98271-99 on Form S-8; and Post-Effective Amendment No. 5 to Registration Statement No. 333-11329-99 on Form S-8 of our reports dated February 26, 2010, relating to the consolidated financial statements and financial statement schedules of CenterPoint Energy, Inc. and subsidiaries (the “Company”), and the effectiveness of the Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of CenterPoint Energy, Inc. for the year ended December 31, 2009.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2010

Exhibit 31.1

CERTIFICATIONS

I, David M. McClanahan, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy, Inc.;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: February 26, 2010

/s/ David M. McClanahan
David M. McClanahan
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Gary L. Whitlock, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy, Inc.;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: February 26, 2010

/s/ Gary L. Whitlock
Gary L. Whitlock
Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of CenterPoint Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2009 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, David M. McClanahan, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ David M. McClanahan
David M. McClanahan
President and Chief Executive Officer
February 26, 2010

Exhibit 32.2

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

In connection with the Annual Report of CenterPoint Energy, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2009 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Gary L. Whitlock, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Gary L. Whitlock
Gary L. Whitlock
Executive Vice President and Chief Financial Officer
February 26, 2010

CENTRAL VERMONT PUBLIC SERVICE CORP

FORM 10-K
(Annual Report)

Filed 03/15/10 for the Period Ending 12/31/09

Address	77 GROVE ST RUTLAND, VT 05701
Telephone	802-773-2711
CIK	0000018808
Symbol	CV
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/27

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

(Mark One)

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

OR

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

Commission file number 1-8222

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of voting and non-voting common equity held by non affiliates of the registrant as of June 30, 2009 (2nd quarter) was approximately $174,206,799 (based on the $18.10 per share closing price of the Company's Common Stock, $6 Par Value, as reported on the New York Stock Exchange on June 30, 2009). In determining who are affiliates of the Company for purposes of computation, it is assumed that directors, officers, and other persons who held on December 31, 2009, more than 5 percent of the issued and outstanding Common Stock of the Company are "affiliates" of the Company. The characterization of such directors, officers, and other persons as affiliates is for the purposes of this computation only and should not be construed as a determination or admission for any other purpose.

On February 26, 2010 there were outstanding 11,729,766 shares of voting Common Stock, $6 Par Value.

DOCUMENTS INCORPORATED BY REFERENCE

The Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 4, 2010 to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Act of 1934, is incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
FORM 10-K - 2009
TABLE OF CONTENTS

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

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

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

We cannot predict the outcome of any of these matters; accordingly, there can be no assurance as to actual results. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Item 1. Business

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

Our wholly owned subsidiaries include:

- Custom Investment Corporation ("Custom"), formed for the purpose of holding passive investments, including the stock of our subsidiaries that invest in regulated business opportunities. On October 13, 2003, we transferred our shares of Vermont Yankee Nuclear Power Corporation ("VYNPC") to Custom. The transfer to Custom does not affect our rights and obligations related to VYNPC. On December 30, 2009, Custom transferred the VYNPC shares back to us. We plan to dissolve Custom in 2010.
- C.V. Realty, Inc., a real estate company that owns, buys, sells and leases real and personal property and interests therein related to the utility business.
- CVPSC - East Barnet Hydroelectric, Inc., formed to finance and construct a hydroelectric facility in Vermont, which became operational September 1, 1984. We have leased and operated it since the in-service date.
- Catamount Resources Corporation ("CRC"), formed to hold our investments in unregulated business opportunities. CRC's wholly owned subsidiary, Eversant Corporation, engages in the sale and rental of electric water heaters in Vermont and New Hampshire through a wholly owned subsidiary, SmartEnergy Water Heating Services, Inc.

- In 2007, we dissolved our wholly owned subsidiary Connecticut Valley Electric Company, Inc. ("Connecticut Valley"), which had been incorporated under the laws of New Hampshire on December 9, 1948. Connecticut Valley distributed and sold electricity in parts of New Hampshire bordering the Connecticut River, until January 1, 2004, when it completed the sale of substantially all of its plant assets and its franchise to Public Service Company of New Hampshire. Its remaining assets were nominal.

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

- We own 58.85 percent of the common stock of VYNPC, which was initially formed by a group of New England utilities to build and operate a nuclear-powered generating plant in Vernon, Vermont. On July 31, 2002, the plant was sold to Entergy Nuclear Vermont Yankee, LLC ("Entergy-Vermont Yankee"). The sale agreement included a purchased power contract between VYNPC and Entergy-Vermont Yankee. Under the purchased power contract, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates, and in turn, bills the purchased power contract charges from Entergy-Vermont Yankee with certain residual costs of service through a FERC tariff to us and the other Vermont Yankee sponsors. Although we own a majority of the shares of VYNPC, our ability to exercise control is effectively restricted by the purchased power contract, the sponsor agreement among the group of New England utilities that formed VYNPC and the composition of the board of directors under which it operates.
- We own 47.05 percent of the common stock and 48.03 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"). In June 2006, VELCO transferred substantially all of its business operations and assets to Vermont Transco LLC ("Transco"). VELCO's wholly owned subsidiary, Vermont Electric Transmission Company, Inc., was formed to finance, construct and operate the Vermont portion of the 450 kV DC transmission line connecting the Province of Quebec with Vermont and the rest of New England.
- We own 33.35 percent of the voting equity units of Transco, which was formed by VELCO and its owners, including us, in June 2006. Transco owns and operates the high-voltage transmission system in Vermont. VELCO and its employees manage the operations of Transco under a Management Services Agreement. VELCO owns 11.32 percent of the voting equity units of Transco. Our total direct and indirect (through our VELCO ownership) interest in Transco is 38.68 percent of the voting equity units.
- We own 2 percent of the outstanding common stock of Maine Yankee Atomic Power Company ("Maine Yankee"), 2 percent of the outstanding common stock of Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and 3.5 percent of the outstanding common stock of Yankee Atomic Electric Company ("Yankee Atomic"). These plants have been decommissioned.

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

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

(c) Narrative Description of Business As a regulated electric utility, we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. The ability to increase our customer base is limited to acquisitions or growth within our service territory. Due to our geographic location and the nature of our customer base, weather and economic conditions significantly affect retail sales revenue. Retail sales volume over the last 10 years has grown at an average rate of less than 1 percent per year, ranging from a decrease of about 3 percent in 2009, due primarily to the poor economy, to increases of over 2 percent in other years.

Our operating revenues consist primarily of retail and resale sales. Retail sales are comprised of sales to a diversified customer mix, including residential, commercial and industrial customers. Sales to the five largest retail customers receiving electric service accounted for about 5 percent of our annual retail electric revenues for 2009, and about 6 percent in 2008 and 2007. Resale sales are comprised of long-term sales to third parties in New England, sales in the energy markets administered by ISO-New England and short-term system capacity sales. Operating revenues as of December 31 consisted of the following:

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

Retail Rates: Our retail rates are set by the Vermont Public Service Board ("PSB") after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital. See Part II, Item 8, Note 7 - Retail Rates and Regulatory Accounting.

Wholesale Rates: We provide wholesale transmission service to 10 network customers and five point-to-point customers under ISO-New England FERC Electric Tariff No. 3, Section II - Open Access Transmission Tariff (Schedules 21-CV and 20A-CV). We maintain an OASIS site for transmission on the ISO-New England web page.

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

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

Wholly Owned Plants: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of 74.2 MW. We operate all of these plants, which include: 1) 20 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.3 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 45.3 MW; 2) two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW; and 3) one diesel peaking unit with a nameplate capacity of 2.4 MW. The diesel plant has been deactivated since 2007 but its capacity is included in the above totals.

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

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

VYNPC: We purchase our entitlement share of Vermont Yankee plant output from VYNPC under a long-term power contract between VYNPC and Entergy-Vermont Yankee. The contract extends through the plant's current license life, which expires in March 2012. Prices per megawatt-hour under the contract range from $43 in 2010 to $45 in 2012, and the contract contains a provision known as the "low market adjuster" that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts.

Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over the amount the plant is producing, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. We are responsible for purchasing replacement energy at these times. The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. The next refueling outage is scheduled for the spring of 2010. We typically enter into forward purchase contracts for replacement power during scheduled outages.

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

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

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

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

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

Independent Power Producers: We purchase power from several Independent Power Producers ("IPPs") who own qualifying facilities under the Public Utilities Regulatory Policies Act of 1978. These facilities use water and biomass as fuel. Most of the power is allocated by a state-appointed purchasing agent that assigns power to all Vermont utilities under PSB rules.

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

See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters and Part II, Item 8, Note 17 - Commitments and Contingencies for additional information related to our power supply and related long-term power contracts.

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

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

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

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

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

Federal Power Act: Certain phases of our business and that of VELCO and Transco, including certain rates, are subject to regulation by the FERC. We are a licensee of hydroelectric developments under Part I of the Federal Power Act and along with Transco, we are interstate public utilities under Parts II and III, as amended and supplemented by the National Energy Act. On February 25, 2009, we received a federal license to continue to operate our Carver Falls hydroelectric facility and on February 26, 2009, we received a federal license to continue to operate our Silver Lake hydroelectric facility. These projects represent about 4.1 MW, or 9 percent of our hydroelectric nameplate capacity.

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

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

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

We cannot presently forecast the costs or other effects that environmental regulation may ultimately have on our existing and proposed facilities and operations. We believe that any such prudently incurred costs related to our utility operations would be recoverable through the ratemaking process. See Part II, Item 8, Note 17 - Commitments and Contingencies.

Competitive Conditions Competition currently takes several forms. At the wholesale level, New England has implemented its version of FERC's "standard market design" ("SMD"), which is a detailed competitive market framework that has resulted in bid-based competition of power suppliers rather than prices set under cost-of-service regulation. Similar versions of SMD have been implemented in New York and a large abutting multi-state region referred to as PJM. At the retail level, customers have long had energy options.

Competition in the energy services market exists between electricity and fossil fuels. In the residential and small commercial sectors, this competition is primarily for electric space and water heating from propane and oil dealers. Competitive issues are cost effectiveness, energy efficiency, service, convenience, cleanliness, automatic delivery and safety.

In the large commercial and industrial sectors many of these same factors are expected to influence demand. Additionally, cogeneration and self-generation can be competitive threats to network electric sales. Competitive risks in these market segments are primarily related to seasonal, one-shift milling operations that can tolerate periodic power outages common to such forms of cogeneration or self-generation, and for industrial or institutional customers with steady heat loads where the generator's waste heat can be used in their manufacturing or space conditioning processes. Competitive advantages for network electricity in those segments can be: cost effectiveness and stability; convenience; cost of back-up power sources or alternatively, reliability; space requirements; noise problems; air emission and site permit issues; and maintenance requirements. However, there may be some circumstances where distributed generation, net metering and cogeneration could provide benefits to us in the constrained areas of our system.

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

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

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

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

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

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

Executive Officers of Registrant
The following sets forth the executive officers. There are no family relationships among the executive officers. The term of each officer is for one year or until a successor is elected. Officers are normally elected annually.

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

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

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

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

Ms. Gamble joined the company in 1989 with 10 years of electric utility and related consulting experience. Ms. Gamble was elected to her present position in August 2001. Ms. Gamble also serves as vice president - strategic change and business services for our subsidiary, Eversant Corporation. She serves as a director for our subsidiaries, Eversant Corporation and SmartEnergy Water Heating Services, Inc. She is also on the board of the Vermont Achievement Center, Rutland Regional Medical Center, Rutland Regional Health Service, and Vermont Public Television. She is a member of the Vermont Supreme Court's Commission on Judicial Operation.

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

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

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

Energy Conservation and Load Management The primary purpose of Conservation and Load Management programs is to offset need for long-term power supply and delivery resources that are more expensive to purchase or develop than customer-efficiency programs, including unpriced external factors such as emissions and economic risk. The Vermont Energy Efficiency Utility (“EEU”), created by the state of Vermont to implement energy efficiency programs throughout Vermont, began operation in January 2000. We have a continuing obligation to provide customer information and referrals, and coordination of customer service, power quality, and any other distribution utility functions, which may intersect with the EEU’s activities.

We have retained the obligation to provide demand side management programs targeted at deferral of our transmission and distribution projects, as identified in Vermont’s Distributed Utility Planning (“DUP”). DUP is designed to ensure that safe, reliable delivery services are provided at least cost. The PSB recently approved a similar process for the bulk transmission lines owned and operated by Transco. The PSB appointed three members of the public, along with representatives of the state’s utilities, including us, to the newly created Vermont System Planning Committee to oversee that process. In 2006, the Vermont Legislature also gave Efficiency Vermont authority to target the delivery of energy efficiency to specific geographic areas to defer transmission and distribution upgrades. This process began for the first time in 2007.

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

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

(e) Available Information

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

Item 1A. Risk Factors

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

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

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

Unexpected ice, wind and snow storms or extraordinarily severe weather can dramatically increase costs, with a significant lapse of time before we recover these costs through our rates. The demand for our services and our ability to provide them without material unplanned expenses are directly affected by weather conditions. We serve a largely rural, rugged service territory with dense forestation that is subject to extreme weather conditions. Storm activity has been significant in recent years, with the two most expensive storms in our history occurring in 2007 and 2008. Our results of operations can be affected by changes in weather. Severe weather conditions such as ice and snow storms, high winds and natural disasters may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period. We typically receive the five-year average of storm restoration costs in our rates. Weather conditions also directly influence the demand for electricity.

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

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

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

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

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

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

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

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

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

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

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

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose the economic benefit of an energy volume equal to close to 50 percent of our total committed supply and have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.5 million annually. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results, if the costs are recovered in retail rates in a timely fashion.

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

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

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

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

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

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

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

We have other business risks related to liquidity. An extended unplanned Vermont Yankee plant outage or similar event could have a significant effect on our liquidity due to the potentially high cost of replacement power and performance assurance requirements arising from purchases through ISO-New England or third parties.

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

Our credit facilities provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements in the form of funds borrowed and letters of credit. We raised $20.9 million, net of issuance costs, in a secondary offering of our common stock in November 2008. The proceeds were used for general corporate purposes including investments in our core infrastructure to maintain system reliability. If we are ever unable to secure needed funding, we would review our corporate goals in response to the financial limitation. Other material risks to cash flow from operations include: loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; increases in net power costs due to lower-than-anticipated margins on sales revenue from excess power or an unexpected power source interruption; required prepayments for power purchases; and increases in performance assurance requirements described above, as a result of high power market prices.

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

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

Likewise, our business follows the economic cycles of the customers we serve. The economic downturn, subsequent recession and increased cost of energy supply have and could continue to adversely affect energy consumption and therefore impact our results of operations. Economic downturns or periods of high energy supply costs typically lead to reductions in energy consumption and increased conservation measures. These conditions could adversely impact the level of energy sales and result in less demand for energy delivery. However, the effect of unanticipated reduced consumer demand on our revenue will be offset to a large degree by the power cost and earnings sharing adjustment mechanism in the alternative regulation plan that became effective January 1, 2009. Anticipated consumer demand is reflected in base rates set annually under the plan.

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

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

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

The costs associated with healthcare or pension obligations could escalate at rates higher than anticipated, which could adversely affect our results of operations and cash flows. Active employee and retiree healthcare and pension costs are a significant part of our cost structure. The costs associated with healthcare or pension obligations could escalate at rates higher than anticipated, which could adversely affect our results of operations and cash flows. Also, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, Pension and Postretirement Medical Benefits.

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

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

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

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

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

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

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

Our properties are operated as a single system that is interconnected by the transmission lines of Transco, New England Power and Public Service Company of New Hampshire. We own and operate 23 small generating stations in Vermont with a total current nameplate capability of 74.2 MW. Our joint ownership interests include: a 1.7769 percent interest in an oil-generating plant in Maine; a 20 percent interest in a wood-, gas- and oil-fired generating plant in Vermont; a 1.7303 percent interest in a nuclear generating plant in Connecticut; and a 47.52 percent interest in a transmission interconnection facility in Vermont. Additional information with respect to these properties is set forth under Part I, Item 1, Business, Sources and Availability of Power Supply and is incorporated herein by reference.

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

Transco's properties consist of approximately 621 miles of high-voltage overhead and underground transmission lines and associated substations. The lines connect on the west with the lines of National Grid New York at the Vermont-New York border near Whitehall, N.Y. and Bennington, Vt., and with the submarine cable of New York Power Authority near Plattsburgh, N.Y.; on the south and east with the lines of National Grid New England, Public Service Company of New Hampshire and Northeast Utilities; on the south with the facilities of Vermont Yankee and with National Grid New England near Adams, Mass.; and on the northern border of Vermont with the lines of Hydro-Quebec near Derby, Vt. and through the Highgate converter station and tie line that we jointly own with several other Vermont utilities.

VELCO's wholly owned subsidiary, Vermont Electric Transmission Company, Inc. has approximately 52 miles of high-voltage DC transmission lines connecting with the transmission line of Hydro-Quebec at the Quebec-Vermont border in the Town of Norton, Vt. and connecting with the transmission line of New England Electric Transmission Corporation, a subsidiary of National Grid USA, at the Vermont-New Hampshire border near New England Power Company's Moore hydroelectric generating station.

Item 3. Legal Proceedings

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

Item 4. Removed and Reserved

PART II

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

(a) Our common stock is listed on the New York Stock Exchange ("NYSE") under the trading symbol CV.

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

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

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

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

So long as any Senior Preferred Stock is outstanding, except as otherwise authorized by vote of two-thirds of such class, if the Common Stock Equity (as defined) is, or by the declaration of any dividend will be, less than 20 percent of Total Capitalization (as defined), dividends on Common Stock (including all distributions thereon and acquisitions thereof), other than dividends payable in Common Stock, during the year ending on the date of such dividend declaration, shall be limited to 50 percent of the Net Income Available for Dividends on Common Stock (as defined) for that year; and if the Common Stock Equity is, or by the declaration of any dividend will be, from 20 percent to 25 percent of Total Capitalization, such dividends on Common Stock during the year ending on the date of such dividend declaration shall be limited to 75 percent of the Net Income Available for Dividends on Common Stock for that year. The defined terms identified above are used herein in the sense as defined in subdivision 8A of our Articles of Association; such definitions are based upon our unconsolidated financial statements. As of December 31, 2009, the Common Stock Equity of our unconsolidated company was 52.4 percent of Total Capitalization.

Our First Mortgage Bond indenture contains certain restrictions on the payment of cash dividends on capital stock and other Restricted Payments (as defined). This covenant limits the payment of cash dividends and other Restricted Payments to our Net Income (as defined) for the period commencing on January 1, 2001 up to and including the month next preceding the month in which such Restricted Payment is to be declared or made, plus approximately $77.6 million. The defined terms identified above are used herein in the sense as defined in Section 5.09 of the Forty-Fourth Supplemental Indenture dated June 15, 2004; such definitions are based upon our unconsolidated financial statements. As of December 31, 2009, $75.7 million was available for such dividends and other Restricted Payments.

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

(e) The performance graph showing our five-year total shareholder return required by this item is included in our Annual Report to Shareholders and is hereby incorporated by reference.

Item 6. Selected Financial Data
(in thousands, except per share amounts)

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

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

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

In this section we discuss our general financial condition and results of operations. Certain factors that may impact future operations are also discussed. Our discussion and analysis is based on, and should be read in conjunction with, the accompanying Consolidated Financial Statements. The discussion below also includes non-GAAP measures referencing earnings per diluted share for variances described below in Results of Operations. We use this measure to provide additional information and believe that this measurement is useful to investors to evaluate the actual performance and contribution of our business activities. This non-GAAP measure should not be considered as an alternative to our consolidated fully diluted earnings per share determined in accordance with GAAP as an indicator of our operating performance. Also, please refer to our "Cautionary Statement Regarding Forward-Looking Information" section preceding Part I, Item 1, Business of this Form 10-K.

COMPANY OVERVIEW

We are regulated by the Vermont Public Service Board ("PSB"), the Federal Energy Regulatory Commission ("FERC") and the Connecticut Department of Public Utility Control with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital. As discussed under the heading Retail Rates and Alternative Regulation below, the PSB approved, with modifications, the alternative regulation plan that we proposed in August 2007, with modifications. The implementation of this plan on January 1, 2009, has provided timelier rate adjustments to reflect changes in power, operating and maintenance costs, which better serve the interests of customers and shareholders.

As a regulated electric utility, we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. The ability to increase our customer base is limited to acquisitions or growth within our service territory. Due to the nature of our customer base, weather and economic conditions can significantly affect retail sales revenue. Retail sales volume over the last 10 years has grown at an average rate of less than 1 percent per year, ranging from a decrease of about 3 percent in 2009, primarily due to the poor economy, to increases of over 2 percent in other years. We currently have sufficient power resources to meet or exceed our forecasted load requirements through March 2012.

Our non-regulated wholly owned subsidiary Catamount Resources Corporation ("CRC") owns Eversant Corporation ("Eversant"), which operates a rental water heater business through its wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. This is not a significant business activity for us.

EXECUTIVE SUMMARY

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

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

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

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

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

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

Other financial initiatives that we continue to focus on include maintaining sufficient liquidity to support ongoing operations, the dividend on our common stock, investing in our electric utility infrastructure, planning for replacement power when our long-term power contracts expire, and evaluating opportunities to further invest in Transco.

Continued focus on these financial initiatives is critical to maintaining our corporate credit rating. We discuss these financial initiatives and the risks facing our business in more detail below.

RETAIL RATES AND ALTERNATIVE REGULATION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

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

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

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

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

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

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

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

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

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

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

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

Based on current projections, Transco expects to need additional equity capital in 2010 and 2011, but its projections are subject to change based on a number of factors, including revised construction estimates, timing of project approvals from regulators, and desired changes in its equity-to-debt ratio. While we have no obligation to make additional investments in Transco, which are subject to available capital and appropriate regulatory approvals, we continue to evaluate investment opportunities on a case-by-case basis. Based on Transco's current projections, we could have an opportunity to make additional investments of up to $43.5 million in 2010 and $11.5 million in 2011, but the timing and amount depend on the factors discussed above and the amounts invested by other owners.

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

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

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

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

Cash Flow Risks Based on our current cash forecasts, we will require outside capital in addition to cash flow from operations and our $40 million and $15 million unsecured revolving credit facilities in order to fund our business over the next few years. Prolonged upheaval in the capital markets could negatively impact our ability to obtain outside capital on reasonable terms. If we were ever unable to obtain needed capital, we would re-evaluate and prioritize our planned capital expenditures and operating activities. In addition, an extended unplanned Vermont Yankee plant outage or similar event could significantly impact our liquidity due to the potentially high cost of replacement power and performance assurance requirements arising from purchases through ISO-New England or third parties. An extended Vermont Yankee plant outage could involve cost recovery via our forced outage insurance policy and recoveries under the PCAM but in general would not be expected to materially impact our financial results, if the costs are recovered in retail rates in a timely fashion. Other material risks to cash flow from operations include: loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; increases in net power costs largely due to lower-than-anticipated margins on sales revenue from excess power or an unexpected power source interruption; required prepayments for power purchases; and increases in performance assurance requirements. It is important to note, however, that our alternative regulation plan sets bands around the earnings in our regulated business, which ensures, in part, that they will not fall below prescribed levels. See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks.See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks.

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

Financing

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

Credit Facility: We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a credit agreement dated November 3, 2008. Our obligation under the credit agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. Financing terms and costs include an annual commitment fee of 0.15 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.7 percent on the average daily amount of letters of credit outstanding. All interest, commission and fee rates are based on our unsecured issuer rating. The facility contains a material adverse effect clause, which permits the lender to deny a transaction at the point of request. We are also required to collateralize any outstanding letter of credit in the event of a default under the credit facility. At December 31, 2009, $23.3 million in loans and no letters of credit were outstanding under the credit facility.

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

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

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

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

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

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

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

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

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

Contractual Obligations Significant contractual obligations as of December 31, 2009 are summarized below.

	Payments Due by Period (dollars in millions)				
Contractual Obligations	Total	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years
Long-term debt (a)	$ 201.6	$ 0.0	$ 43.3	$ 5.8	$ 152.5
Interest on long-term debt (b)	153.5	11.1	20.4	19.7	102.3
Redeemable preferred stock	1.0	1.0	0.0	0.0	0.0
Capital lease (c)	6.5	1.4	2.4	2.0	0.7
Operating leases - vehicle and other (d)	7.0	1.8	3.1	1.8	0.3
Purchased power contracts (e)	635.2	144.3	246.1	140.2	104.6
Nuclear decommissioning and other closure costs (f)	8.5	1.4	3.2	2.9	1.0
Other purchase obligations (g)	0.7	0.7	0.0	0.0	0.0
Total Contractual Obligations	$ 1,014.0	$ 161.7	$ 318.5	$ 172.4	$ 361.4

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

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

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

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

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

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

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

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

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

Capitalization Our capitalization for the past two years follows:

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

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

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

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

Performance Assurance At December 31, 2009, we had posted $5.4 million of collateral under performance assurance requirements for certain of our power contracts, all of which was represented by restricted cash. We are subject to performance assurance requirements through ISO-New England under the FERC-filed tariff and Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $2.7 million with ISO-New England. This is a marked improvement from the past. Prior to the receipt of our current ratings from Moody's, our below-investment-grade ratings meant we had a credit limit of zero with ISO-New England, and were required to post collateral for net purchases. We are now required to post collateral for only net purchased power transactions in excess of our new credit limit. Additionally, we are currently selling power in the wholesale market pursuant to contracts with third parties, and are required to post collateral under certain conditions defined in the contracts.

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

Off-balance-sheet arrangements We do not use off-balance-sheet financing arrangements, such as securitization of receivables, nor obtain access to assets through special purpose entities. We have letters of credit that are described in Financing above. We lease our vehicles and related equipment under operating lease agreements. These operating lease agreements are described in Part II, Item 8, Note 17 - Commitments and Contingencies.

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

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

On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). Under the terms of the agreements with Catamount and Diamond Castle, we agreed to indemnify them, and certain of their respective affiliates as described in Part II, Item 8, Note 17 - Commitments and Contingencies.

OTHER BUSINESS RISKS

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

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

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

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

Power Supply Risk: Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that the plant could be shut down earlier than expected if Entergy-Vermont Yankee determines that it is not economical to continue operating the plant, or due to environmental concerns. Hydro-Quebec contract deliveries end in 2016, but the average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015. There is a risk that future sources available to replace these contracts may not be as reliable and the price of such replacement power could be significantly higher than what we have in place today. However, the company has been planning for the expiration of these contracts for several years, and a robust effort, described further below, is in place to ensure a safe, reliable, environmentally beneficial and relatively affordable energy supply going forward.

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

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

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

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose the economic benefit of an energy volume equal to close to 50 percent of our total committed supply and have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.5 million annually. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results, if the costs are recovered in retail rates in a timely fashion.

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

Wholesale Power Market Price Risk: Our material power supply contracts are with Hydro-Quebec and VYNPC. These contracts comprise the majority of our total annual energy (mWh) purchases. If one or both of these sources becomes unavailable for a period of time, there could be exposure to high wholesale power prices and that amount could be material.

We are responsible for procuring replacement energy during periods of scheduled or unscheduled outages of our power sources. Average market prices at the times when we purchase replacement energy might be higher than amounts included for recovery in our retail rates. We have forced outage insurance through March 21, 2011 to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The Power Cost Adjustment Mechanism within our alternative regulation plan allows recovery of power costs.

Market Risk: See Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may have a material impact on our results of operations. In the event that we determine our regulated business no longer meets the criteria for regulated operations and there is not a rate mechanism to recover these costs, the impact would, among other things, be a charge to operations of $11.8 million pre-tax at December 31, 2009. The continued applicability of accounting for regulated operations is assessed at each reporting period. We believe our regulated operations will be subject to this accounting guidance for the foreseeable future. Also, see Recent Accounting Pronouncements below.

Valuation of Long-Lived Assets We periodically evaluate the carrying value of long-lived assets, including our investments in nuclear generating companies, our unregulated investments, and our interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. No impairments of long-lived assets were recorded in 2009 or 2008.

Revenues Revenues from the sale of electricity to retail customers are based on PSB-approved rates. Our revenues are recorded when service is rendered or when energy is delivered to customers. We accrue revenue based on estimates of electric service rendered and unbilled revenue at the end of each accounting period. This unbilled revenue is estimated each month based on daily generation volumes (territory load), estimated line losses and applicable customer rates. We estimate line losses at 5.2 percent. A 1 percent change in line losses would result in a $2.8 million change in annual revenues. Factors that could affect the estimate of unbilled revenues include seasonal weather conditions, changes in meter reading schedules, the number and type of customers scheduled for each meter reading date, estimated customer usage by class, applicable customer rates and estimated losses of energy during transmission and delivery. Unbilled revenues totaled $20.8 million at December 31, 2009 and $18.5 million at December 31, 2008. We believe that these assumptions have resulted in a reasonable approximation of our unbilled revenues and are reasonably likely to continue.

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

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

The guidance also required companies with early benefit measurement dates to change their measurement date in 2008 to correspond with their fiscal year-end and to record the financial statement impact of the change as an adjustment to retained earnings. We estimated that changing the annual benefit measurement date from September 30 to December 31 would result in a pre-tax charge of $1.3 million, of which $0.1 million was recorded to retained earnings. We received PSB approval for recovery of the regulated utility portion of the impact resulting from the change in measurement date. Accordingly, we recorded a regulatory asset of $1.2 million in the first quarter of 2008 that is being amortized over five years, beginning in February 2008.

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

Discount Rate : The discount rate is used to record the value of benefits, which are based on future projections, in terms of today's dollars. The selection methodology used in determining the discount rate includes portfolios of "Aa" bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million in par value. As of December 31, 2009, the pension discount rate changed from 6.15 percent to 6 percent and the postretirement medical discount rate changed from 6.05 percent to 5.5 percent. The conditions in the credit market have been volatile since the third quarter of 2008, and decreases in the discount rates could increase our benefit obligations, which may also result in higher costs and funding requirements.

Expected Return on Plan Assets ("ROA") : We project the future ROA based principally on historical returns by asset category and expectations for future returns, based in part on simulated capital market performance over the next 10 years. The projected future value of assets reduces the benefit obligation a company will record. The expected ROA long-term assumption was 7.85 percent as of December 31, 2008 and December 31, 2009. This rate was also used to determine the annual expense for 2009 and will be used to determine the 2010 expense.

Rate of Compensation Increase: We project employees' compensation increases, including annual increases, promotions and other pay adjustments, based on our expectations for future long-term experience reflecting general trends. This projection is used to estimate employees' pension benefits at retirement. The projected rate of compensation increase was 4.25 percent as of the measurement date in 2008 and 2009.

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

Amortization of Gains/(Losses): The assets and liabilities of the pension and postretirement medical benefit plans are affected by changing market conditions as well as differences between assumed and actual plan experience. Such events result in gains and losses. Investment gains and losses are deferred and recognized in pension and postretirement medical benefit costs over a period of years. If, as of the annual measurement date, the plan's unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, the excess is amortized over the average remaining service period of active plan participants. This 10-percent corridor method helps to mitigate volatility of net periodic benefit costs from year to year. Asset gains and losses related to certain asset classes such as equity, emerging-markets equity, high-yield debt and emerging-markets debt are recognized in the calculation of the market-related value of assets over a five-year period. The fixed income assets are invested in longer-duration bonds to match changes in plan liabilities. The gains and losses related to this asset class are recognized in the market-related value of assets immediately. Also see Part II, Item 8, Note 15 - Pension and Postretirement Medical Benefits.

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

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

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

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

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

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

Derivative Financial Instruments We account for various power contracts as derivatives under the provisions of FASB's guidance for derivatives and hedging. This guidance requires that derivatives be recorded on the balance sheet at fair value. We estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and market data and other assumptions. The value of each forward energy derivative contract, measured over its entire duration, is primarily based on the difference between contract prices and non-binding broker quotes provided from a paid pricing service, consistent with industry practice. Price information for forward energy derivative contracts is not readily observable in the market. Based on management discussions with the broker concerning development of price quotes, information has been considered including prices from other similar contracts. Since this information is not publicly quoted or readily observable, we have assessed our forward energy derivatives as Level 3 fair value measures. Fair value estimates involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future energy prices, including supply and demand levels and future price volatility. Based on a PSB-approved Accounting Order, we record the change in fair value of all power contract derivatives as deferred charges or deferred credits on the balance sheet, depending on whether the change in fair value is an unrealized loss or gain. The corresponding offsets are recorded as current and long-term assets or liabilities depending on the duration of the contracts.

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

Environmental Reserves Environmental reserves are estimated and accrued using a probabilistic model when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our environmental reserve is for three sites in various stages of remediation. Our cost estimates for two of the sites are based on engineering evaluations of possible remediation scenarios and a Monte Carlo simulation. The cost estimate for the third site is less than $0.1 million. The liability estimate includes costs for remediation, monitoring and other future activities. At December 31, 2009, our reserve for the three sites was $1.6 million and it was $1.7 million at December 31, 2008. These estimates are based on currently available information from presently enacted state and federal environmental laws and regulations. The estimates are subject to revisions in future periods based on actual costs or new information concerning either the level of contamination at the site or newly enacted laws and regulations.

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

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

Income Taxes We follow FASB's guidance and methodology for estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. The application of income tax law is complex and we are required to make many subjective assumptions and judgments regarding our income tax exposures. We record income tax expense quarterly using an estimated annualized effective tax rate. Adjustments to these estimates and changes in our subjective assumptions and judgments can materially affect amounts recognized on the income statement, balance sheet and statement of cash flows.

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

RESULTS OF OPERATIONS

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

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

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

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

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

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

Consolidated Income Statement Discussion The following includes a more detailed discussion of the components of our Consolidated Statements of Income and related year-over-year variances.

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

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

The average number of retail customers is summarized below:

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

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

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

2009 vs. 2008

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

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

2008 vs. 2007

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

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

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

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

Purchased Power - affiliates and other: Power purchases made up 49 percent of total operating expenses in 2009, 51 percent in 2008 and 52 percent in 2007. Most of these purchases are made under long-term contracts. These contracts and other power supply matters are discussed in more detail in Power Supply Matters below. Purchased power expense and volume are summarized below:

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

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

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

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

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

2009 vs. 2008

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

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

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

<u>2008 vs. 2007</u>
Purchased power expense increased $4.7 million, or 2.9 percent, due to the following factors:
- Purchased power costs under long-term contracts increased $4.4 million in 2008, due primarily to increased purchases from IPPs at higher prices and from increased Vermont Yankee plant output we purchase at favorable rates under the PPA. The Vermont Yankee plant operated at nearly full capacity in 2008 with the exception of a few small derates and the planned refueling outage in the fourth quarter. These increases were offset by fewer purchases from Hydro-Quebec due to a 5 percent decrease in the annual load factor.
- Other purchases increased $0.9 million in 2008 resulting from higher average prices for replacement energy purchased during the Vermont Yankee refueling outage and derate described above.
- Nuclear decommissioning costs decreased $0.5 million in 2008 and are associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs are based on FERC-approved tariffs. The decrease is largely due to lower revenue requirements for Connecticut Yankee and Maine Yankee.

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

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

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

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

Transmission - other: The majority of these expenses are for purchases of regional transmission service under the NOATT and charges for the Phase I and II transmission facilities. The increase of $4.9 million for 2009 versus 2008 primarily resulted from higher rates and overall transmission expansion in New England. The increase of $2.3 million for 2008 versus 2007 was primarily for the same reason.

Other operation : These expenses are related to operating activities such as customer accounting, customer service, administrative and general activities, regulatory deferrals and amortizations, and other operating costs incurred to support our core business. The increase of $3.4 million for 2009 versus 2008 was primarily due to $2.2 million of higher net regulatory amortizations, primarily related to the recovery of 2008 major storm costs and $0.5 million of higher reserves for uncollectible accounts, primarily due to a customer bankruptcy, partially offset by lower professional service costs due to a large software project in 2008 that did not recur in 2009.

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

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

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

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

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

Income tax expense: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods. There was no significant variance for 2009 versus 2008 or for 2008 versus 2007.

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

Other Income and Other Deductions These items are related to the non-operating activities of our utility business and the operating and non-operating activities of our non-regulated businesses through CRC. CRC's earnings were $0.9 million in 2009, $0.2 million in 2008 and $0.5 million in 2007. The variances in income statement line items that comprise other income and other deductions on the Consolidated Statements of Income are shown in the table below (dollars in thousands).

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

* variance exceeds 100 percent

Equity in earnings of affiliates: These earnings are related to our equity investments including VELCO, Transco and VYNPC. The increase of $1.2 million for 2009 versus 2008 is principally due to the $3.1 million investment that we made in Transco in December 2008. The increase of $9.8 million for 2008 versus 2007 is principally from increased earnings resulting from an additional $53 million investment we made in Transco in December 2007.

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

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

Income tax expense: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods. There was no significant variance for 2009 versus 2008. See Part II, Item 8, Note 16 – Income Taxes for the change in income expense for 2008 versus 2007.

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

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

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

* variance exceeds 100 percent

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

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

POWER SUPPLY MATTERS

Power Supply Management Our power supply portfolio includes a mix of baseload and dispatchable resources. These sources are used to serve our retail electric load requirements plus any wholesale obligations into which we enter. We manage our power supply portfolio by attempting to optimize the use of these resources, and through wholesale sales and purchases to maintain a balance between our power supplies and load obligations.

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

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

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

	2009	2008	2007
Nuclear	**55%**	50%	48%
Hydro	**38%**	39%	39%
Oil and wood	**4%**	5%	6%
Other	**3%**	6%	7%
Total	**100%**	100%	100%

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

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

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

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

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

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

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

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

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

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

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose the economic benefit of an energy volume equal to close to 50 percent of our total committed supply and have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.5 million annually. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results if the costs are recovered in a timely fashion.

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

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

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

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

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

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

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

Wholly owned hydro and thermal: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of about 74.2 MW. We operate all of these plants, which include 20 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.3 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 45.3 MW; two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW; and one diesel peaking unit with a nameplate capacity of 2.4 MW, which is currently deactivated. In 2009, we upgraded our Arnold Falls unit in St. Johnsbury, VT, investing approximately $1.4 million in the facility. The improvements are expected to ensure the plant's long-term viability and increase production by about 10 percent.

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

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

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

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

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

ISO-New England has a market mechanism referred to as the Forward Capacity Market ("FCM") to compensate owners of new and existing generation capacity, including demand reduction. ISO-New England believes that higher capacity payments in constrained areas will encourage the development of new generation where needed. Capacity requirements for load-serving entities, including us, are based on each entity's proportionate share of ISO-New England's prior year coincident peak demand and the amount of qualifying capacity in the pool. Based on specified rates through May 2010, we expect net FCM charges of about $2.5 million in 2010.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Decommissioned Nuclear Plants We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. As of December 31, 2009, all three have completed decommissioning activities and their operating licenses have been amended to operation of Independent Spent Fuel Storage Installation. They remain separately responsible for safe storage of each plant's spent nuclear fuel and waste at the sites until the DOE meets its obligation to remove the material from the site or until some other suitable storage arrangement can be developed. All three collect decommissioning and closure costs through FERC-approved wholesale rates charged under power purchase agreements with several New England utilities, including us. We believe that, based on historical rate recovery, our share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. However, if the FERC disallows recovery of any of their costs, there is a risk that the PSB would disallow recovery of our share in retail rates.

Based on estimates from Maine Yankee, Connecticut Yankee and Yankee Atomic as of December 31, 2009, the total remaining approximate cost for decommissioning and other costs of each plant is as follows: $47.9 million for Maine Yankee, $274.1 million for Connecticut Yankee and $58.8 million for Yankee Atomic. Our share of the remaining obligations amounts to $1 million for Maine Yankee, $5.5 million for Connecticut Yankee and $2.1 million for Yankee Atomic. These estimates may be revised from time to time based on information available regarding future costs.

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

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

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

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

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

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

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

TRANSMISSION MATTERS

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

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

Transco has been working with us on a project to solve load-serving and reliability issues related to a 46-kV transmission line extending from Bennington to Brattleboro, Vt., which we refer to as the Southern Loop. It serves about 25 percent of our load. We initiated a public engagement process in late 2005 to gain input on how best to improve and ensure reliable electric service in southern Vermont. Based on input from this process, in the fourth quarter of 2006 we filed a petition with the PSB for approval to purchase and install two synchronous condensers along the Southern Loop. This project was approved by the PSB in April 2008. Work commenced in June 2008 and was completed in February 2009. The condensers are rotating machines similar to motors used to provide reactive support on the electric power transmission systems without burning fuel. The condensers have improved the reliability in the Stratton/Manchester area of the Southern Loop. Transco also worked with us on a proposal to construct additional transmission lines in the area in order to improve reliability to the Brattleboro area of the Southern Loop. This includes the construction of a new line in the existing 345 kV corridor between Vermont Yankee in Vernon and our substation in Coolidge. The plan also included a new substation in Vernon and an expansion of the Coolidge Substation. These components are collectively known as the "Coolidge Connector." To address local reliability problems on our system, on February 12, 2009 the PSB also approved construction of a new substation in Newfane and a 345 kV loop between the new substation and the 345 kV Vernon-to-Cavendish line. The effort to involve the public in a meaningful dialogue about these issues has been hailed as a vast improvement over previous project-review processes. We believe this new way of conducting business led to better solutions, lower costs, and improved community relations. In fact, a statewide transmission planning committee was created in the wake of the Southern Loop outreach effort, patterned in many respects after it.

The Regional Transmission Organization ("RTO") for New England began operating on February 1, 2005 pursuant to FERC Order 2000. We are a participant in this organization, which provides the PTF service on a non-discriminatory basis throughout New England via the NOATT.

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

RECENT ENERGY POLICY INITIATIVES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

RECENT ACCOUNTING PRONOUNCEMENTS

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

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

Also, see Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies to the accompanying Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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

Wholesale Power Market Price Risk Our most significant power supply contracts are with Hydro-Quebec and VYNPC. Combined, these contracts amount to approximately 90 percent of our total energy (mWh) purchases. The contracts are described in more detail in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters and Part II, Item 8, Note 17 - Commitments and Contingencies. Summarized information regarding power purchases under these contracts follows.

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

(a) Under the terms of the Hydro-Quebec contract, there is a defined energy rate that escalates at the general inflation rate based on the U.S. Gross National Product Implicit Price Deflator ("GNPIPD") and capacity rates are constant with the potential for small reductions if interest rates decrease below average values set in prior years.
(b) Under the terms of the contract with VYNPC the energy price generally ranges from 3.9 cents to 4.5 cents per kilowatt-hour through 2012. Effective November 2005, the contract prices are subject to a "low-market adjuster" mechanism.

Currently, our power forecast shows energy purchase and production amounts in excess of our load requirements through 2011. Because of this projected power surplus, we enter into forward sale transactions from time to time to reduce price volatility of our net power costs. The effect of increases or decreases in average wholesale power market prices is highly dependent on whether our net power resources at the time are sufficient to meet load requirements. If they are not sufficient to meet load requirements, such as when power from Vermont Yankee is not available as expected, we are in a purchase position. In that case, increased wholesale power market prices would increase our net power costs. If our net power resources are sufficient to meet load requirements, we are in a sale position. In that case, increased wholesale power market prices would decrease our net power costs. The Power Cost Adjustment Mechanism within our alternative regulation plan allows more timely recovery of our power costs in 2009, 2010 and 2011.

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

	Forward Energy Contracts	**Financial Transmission Rights**	**Hydro-Quebec Sellback #3**	**Total**
Total fair value at December 31, 2008	$ 12,753	$ 136	$ (4,069)	$ 8,820
Gains and losses (realized and unrealized)				
Included in earnings	23,226	(113)	0	23,113
Included in Regulatory and other assets/liabilities	(12,484)	0	3,920	(8,564)
Purchases, sales, issuances and net settlements	(23,226)	111		(23,115)
Total fair value at December 31, 2009	$ 269	$ 134	$ (149)	$ 254
Estimated fair value at December 31, 2009 for changes in projected market price:				
10 percent increase	$ (2,623)	$ 148	$ (985)	$ (3,460)
10 percent decrease	$ 3,182	$ 121	$ 0	$ 3,303

Pursuant to a PSB-approved Accounting Order, changes in fair value of all power-related derivatives are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the change in fair value is an unrealized loss or unrealized gain, with an offsetting amount recorded as a decrease or increase in the related derivative asset or liability.

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

Interest Rate Risk: Interest rate changes could impact the value of the debt securities in our pension and postretirement medical benefit trust funds and the valuations of estimated pension and other benefit liabilities, affecting pension and other benefit expenses, contributions to the external trust funds and ultimately our ability to meet future pension and postretirement benefit obligations. We have adopted a diversified investment policy with a goal to mitigate these market impacts. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, and Part II, Item 8, Note 15 - Pension and Postretirement Medical Benefits.

Interest rate changes could also impact the value of the debt securities in our Millstone Unit #3 decommissioning trust. At December 31, 2009, the trust held debt securities in the amount of $1.2 million.

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

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

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

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

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits. We did not audit the financial statements of Vermont Transco LLC (“Transco”) and Vermont Electric Power Company, Inc. (“Velco”), the Company’s investments in which are accounted for by use of the equity method. The Company’s equity of $126,742,000 and $99,121,000 in Transco’s and Velco’s net assets as of December 31, 2009 and 2008, respectively, and of $17,124,000, $16,102,000 and $5,886,000 in Transco’s and Velco’s net income for each of the three years in the period ended December 31, 2009, are included in the accompanying consolidated financial statements. Those financial statements were audited by other auditors whose reports (which as to Velco included an explanatory paragraph concerning a change in accounting for non-controlling interests) have been furnished to us, and our opinion, insofar as it relates to the amounts included for Transco and Velco, is based solely on the reports of other auditors.

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

In our opinion, based on our audits and the reports of other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of Central Vermont Public Service Corporation and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 12, 2010 expresses an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 12, 2010

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

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

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

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

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

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

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

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

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

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

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

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

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

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

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

	Common Stock		Treasury Stock			Accumulated		
	Shares Issued	Amount	Shares	Amount	Other Paid-in Capital	Other Comprehensive Loss	Retained Earnings	Total
Balance, December 31, 2006	12,382,801	$ 74,297	(2,249,975)	$ (51,186)	$ 54,225	$ (544)	$ 102,560	$ 179,352
Cumulative effect of adoption of FIN 48							120	120
Adjusted balance at January 1, 2007	12,382,801	$ 74,297	(2,249,975)	$ (51,186)	$ 54,225	$ (544)	$ 102,680	$ 179,472
Net Income							15,804	15,804
Other comprehensive income						166		166
Dividend reinvestment plan	9,721	58	19,847	452	475			985
Stock options exercised	75,775	455			1,097			1,552
Share-based compensation:								
Common and nonvested shares	6,390	38			174			212
Performance share plans					333			333
Dividends declared:								
Common - $0.92 per share							(9,366)	(9,366)
Non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					17			17
Loss on reacquisition of capital stock					3		(3)	
Balance, December 31, 2007	12,474,687	$ 74,848	(2,230,128)	$ (50,734)	$ 56,324	$ (378)	$ 108,747	$ 188,807
Adjust to initially apply SFAS 158 measurement provision, net of tax						4	(46)	(42)
Net income							16,385	16,385
Other comprehensive income						146		146
Common stock issuance, net of issuance costs	1,190,000	7,140			13,760			20,900
Dividend reinvestment plan			54,236	1,233				1,233
Stock options exercised	67,050	402			882			1,284
Share-based compensation:								
Common & nonvested shares	3,891	23			65			88
Performance share plans	15,089	91			418			509
Dividends declared:								
Common - $0.92 per share							(9,500)	(9,500)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					17			17
Gain (loss) on capital stock					23		(3)	20
Balance, December 31, 2008	**13,750,717**	**$ 82,504**	**(2,175,892)**	**$ (49,501)**	**$ 71,489**	**$ (228)**	**$ 115,215**	**$ 219,479**
Net income							20,749	20,749
Other comprehensive income						19		19
Common stock issuance costs					(179)			(179)
Dividend reinvestment plan	19,468	117	46,819	1,065	255			1,437
Stock options exercised	36,160	217			284			501
Share-based compensation:								
Common & nonvested shares	4,530	27			58			85
Performance share plans	25,093	151			417			568
Dividends declared:								
Common - $0.92 per share							(10,720)	(10,720)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense					16			16

Gain (loss) on capital stock					(161)		(3)	(164)
Balance, December 31, 2009	**13,835,968**	**83,016**	**(2,129,073)**	**(48,436)**	**72,179**	**(209)**	**124,873**	**$ 231,423**

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Our wholly owned subsidiaries include Custom Investment Corporation, C.V. Realty, Inc., Central Vermont Public Service Corporation - East Barnet Hydroelectric, Inc. ("East Barnet") and Catamount Resources Corporation ("CRC"). We have equity ownership interests in Vermont Yankee Nuclear Power Corporation ("VYNPC"), Vermont Electric Power Company, Inc. ("VELCO"), Vermont Transco LLC ("Transco"), Maine Yankee Atomic Power Company ("Maine Yankee"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and Yankee Atomic Electric Company ("Yankee Atomic").

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

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

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

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

Investments in entities over which we do not maintain a controlling financial interest are accounted for using the equity method when we have the ability to exercise significant influence over their operations. Under this method, we record our ownership share of the net income or loss of each investment in our consolidated financial statements. We have concluded that consolidation of these investments is not required under FASB's consolidation guidance for variable interest entities. See Part II, Item 8, Note 3 - Investments in Affiliates.

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

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

Regulatory Accounting Our utility operations are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility and Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. As required, we prepare our financial statements in accordance with FASB's guidance for regulated operations. The application of this guidance results in differences in the timing of recognition of certain expenses from those of other businesses and industries. In order for us to report our results under the accounting for regulated operations, our rates must be designed to recover our costs of providing service, and we must be able to collect those rates from customers. If rate recovery of the majority of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, we would reassess whether this accounting standard would continue to apply to our regulated operations. In the event we determine that we no longer meet the criteria for applying the accounting for regulated operations, the accounting impact would be a charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, we believe future recovery of our regulatory assets is probable. Criteria that could give rise to the discontinuance of accounting for regulated operations include: 1) increasing competition that restricts a company's ability to establish prices to recover specific costs, and 2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. In the event that we no longer meet the criteria under the guidance for regulated operations and there is not a rate mechanism to recover these costs, the impact would, among other things, result in a charge to operations of $11.8 million pre-tax at December 31, 2009. See Part II, Item 8, Note 7 - Retail Rates and Regulatory Accounting for additional information.

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

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

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

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

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

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

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

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

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

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

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

Valuation of Long-Lived Assets We periodically evaluate the carrying value of long-lived assets, including our investments in nuclear generating companies, our unregulated investments, and our interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. No impairments of long-lived assets were recorded in 2009, 2008 or 2007.

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

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

Property Under Capital Leases We record our commitments with respect to the Hydro-Quebec Phase I and II transmission facilities, and other equipment, as capital leases. At December 31, 2009, Property under Capital Leases was comprised of $24.8 million of original cost less $19.5 million of accumulated amortization. At December 31, 2008, Property under Capital Leases was comprised of $24.6 million of original cost less $18.5 million of accumulated amortization. See Part II, Item 8, Note 17 - Commitments and Contingencies.

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

Allowance for Funds Used During Construction Allowance for funds used during construction ("AFUDC") is a non-cash item that is included in the cost of utility plant and represents the cost of borrowed and equity funds used to finance construction. Our AFUDC rates were 7.8 percent in 2009, and 8.6 percent in 2008 and 2007. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense on the Consolidated Statements of Income. The cost of equity funds is recorded as other income on the Consolidated Statements of Income.

Asset Retirement Obligations Changes to asset retirement obligations on the Consolidated Balance Sheets follow (dollars in thousands):

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

We have legal retirement obligations for decommissioning related to our joint-owned nuclear plant, Millstone Unit #3, and have an external trust fund dedicated to funding our share of future costs. The year-end aggregate fair value of the trust fund was $5.1 million in 2009 and $4.2 million in 2008, and is included in Investments and Other Assets on the Consolidated Balance Sheets.

We consider our past practices, industry practices, management's intent and the estimated economic lives of the assets in determining whether conditional asset retirement obligations can be reasonably estimated. Asset retirement obligations are recognized for items that can be reasonably estimated such as asbestos removal, disposal of polychlorinated biphenyls in certain transformers and breakers, and mercury in batteries and certain meters. We have not recorded an asset retirement obligation associated with asbestos abatement at certain of our sites because the range of time over which we may settle these obligations is unknown and cannot be reasonably estimated.

Non-legal Removal Costs: Our regulated operations collect removal costs in rates for certain utility plant assets that do not have associated legal asset retirement obligations. Non-legal removal costs of about $10.7 million in 2009 and $10 million in 2008 are included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Environmental Liabilities We are engaged in various operations and activities that subject us to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. Our policy is to accrue a liability for those sites where costs for remediation, monitoring and other future activities are probable and can be reasonably estimated. See Part II, Item 8, Note 17 - Commitments and Contingencies.

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

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

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

Share-Based Compensation Share-based compensation costs are measured at the grant date based on the fair value of the award and recognized as expense on a straight-line basis over the requisite service period. See Part II, Item 8, Note 8 - Share-Based Compensation.

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

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

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

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

Restricted Cash Restricted cash includes funds held by ISO-New England for performance assurance requirements described in Part II, Item 8, Note 17 - Commitments and Contingencies.

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

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

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

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

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

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

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

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

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

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

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

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

Dividends Declared Per Share of Common Stock: The timing of common stock dividend declarations fluctuates whereas the dividend payments are made on a quarterly basis. In 2009, 2008 and 2007, we declared and paid cash dividends of 92 cents per share of common stock.

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

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

Construction and plant expenditures on the Consolidated Statements of Cash Flows reflect actual payments made during the periods. Construction and plant-related expenditures are accrued at the end of each reporting period. At December 31, 2009, $0.5 million of construction and plant-related accruals was included in Accounts Payable, and $0.6 million was included in Other Current Liabilities. At December 31, 2008, less than $0.1 million of construction and plant-related accruals was included in Accounts Payable, and $2.1 million was included in Other Current Liabilities.

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

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

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

Recently Adopted Accounting Policies

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

In April 2009, FASB issued additional guidance to determine the fair value when the volume and level of activity for the asset or liability have significantly decreased and identifying transactions that are not orderly. It does not change the objective of fair value measurements when market activity declines. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date under current market conditions. The adoption of this guidance as of June 30, 2009 did not materially affect our financial position, results of operations or cash flows.

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

Recent Accounting Pronouncements Not Yet Adopted

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

NOTE 2 - EARNINGS PER SHARE ("EPS")

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

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

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

NOTE 3 - INVESTMENTS IN AFFILIATES
Our equity method investments and equity in earnings from those investments follow (dollars in thousands):

	Direct Ownership	Investment At December 31 2009	Investment At December 31 2008	Equity in Earnings As of December 31 2009	Equity in Earnings As of December 31 2008	Equity in Earnings As of December 31 2007
Vermont Electric Power Company, Inc.:						
Common stock	47.05%	**$ 11,726**	$ 11,257			
Preferred stock	48.03%	**$ 268**	$ 267			
Subtotal		**11,994**	11,524	**$ 1,776**	$ 1,296	$ 1,404
Vermont Transco LLC (a)	33.35%	**114,748**	87,597	**15,348**	14,806	4,482
Vermont Yankee Nuclear Power Corporation	58.85%	**2,830**	2,763	**328**	144	431
Connecticut Yankee Atomic Power Company	2.00%	**65**	259	**13**	9	94
Maine Yankee Atomic Power Company	2.00%	**36**	34	**2**	6	8
Yankee Atomic Electric Company	3.50%	**60**	55	**5**	3	11
Total Investments in Affiliates		**$ 129,733**	$ 102,232	**$ 17,472**	$ 16,264	$ 6,430

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

Undistributed earnings of these affiliates, included in Retained Earnings on our Consolidated Balance Sheets, amounted to $15.2 million at December 31, 2009 and $8.5 million at December 31, 2008. Of these amounts, $14.5 million at December 31, 2009 and $8.2 million at December 31, 2008 were from our investment in Transco.

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

We invested $20.8 million in Transco in 2009 and $3.1 million in 2008. Our direct ownership interest was 33.35 percent at December 31, 2009 and 33.02 percent at December 31, 2008. Our ownership interest in Transco is represented by Class A Units that receive a return on equity investments of 11.5 percent under the 1991 Transmission Agreement ("VTA"). At December 31, 2009, our total direct and indirect interest in Transco was 38.68 percent. It was 39.67 percent at December 31, 2008. Transco is a variable interest entity but we are not the primary beneficiary.

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