CENTERPOINT ENERGY INC
Form 10-K
March 01, 2011

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

Form 10-K

(Mark One)

þ	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010 OR
o	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 1-31447

CenterPoint Energy, Inc.
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	74-0694415 (I.R.S. Employer Identification No.)
1111 Louisiana Houston, Texas 77002 (Address and zip code of principal executive offices)	(713) 207-1111 (Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value and associated rights to purchase preferred stock	New York Stock Exchange Chicago 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 þ No o

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 o No þ

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

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 þ No o

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 the registrants' 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. þ

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 definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the voting stock held by non-affiliates of CenterPoint Energy, Inc. (CenterPoint Energy) was $5,507,110,378 as of June 30, 2010, using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of February 15, 2011, CenterPoint Energy had 424,849,673 shares of Common Stock outstanding. Excluded from the number of shares of Common Stock outstanding are 166 shares held by CenterPoint Energy as treasury stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2011 Annual Meeting of Shareholders of CenterPoint Energy, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2010, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from those expressed or implied by these statements. You can generally identify our forward-looking statements by the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal "may," "objective," "plan," "potential," "predict," "projection," "should," "will" or other similar words.

We have based our forward-looking statements on our management's beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied by our forward-looking statements are described under "Risk Factors" in Item 1A and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Certain Factors Affecting Future Earnings" and " – Liquidity and Capital Resources – Other Factors That Could Affect Cash Requirements" in Item 7 of this report, which discussions are incorporated herein by reference.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement.

PART I

Item 1. Business

OUR BUSINESS

Overview

We are a public utility holding company whose indirect wholly owned subsidiaries include:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in a 5,000-square mile area of the Texas Gulf Coast that includes the city of Houston; and

- CenterPoint Energy Resources Corp. (CERC Corp. and, together with its subsidiaries, CERC), which owns and operates natural gas distribution systems in six states. Subsidiaries of CERC Corp. own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of CERC Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

Our reportable business segments are Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. From time to time, we consider the acquisition or the disposition of assets or businesses.

Our principal executive offices are located at 1111 Louisiana, Houston, Texas 77002 (telephone number: 713-207-1111).

We make available free of charge on our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the Securities and Exchange Commission (SEC). Additionally, we make available free of charge on our Internet website:

- our Code of Ethics for our Chief Executive Officer and Senior Financial Officers;
- our Ethics and Compliance Code;
- our Corporate Governance Guidelines; and
- the charters of the audit, compensation, finance, governance and strategic planning committees of our Board of Directors.

Any shareholder who so requests may obtain a printed copy of any of these documents from us. Changes in or waivers of our Code of Ethics for our Chief Executive Officer and Senior Financial Officers and waivers of our Ethics and Compliance Code for directors or executive officers will be posted on our Internet website within five business days of such change or waiver and maintained for at least 12 months or reported on Item 5.05 of Form 8-K. Our website address is www.centerpointenergy.com. Except to the extent explicitly stated herein, documents and information on our website are not incorporated by reference herein.

Electric Transmission & Distribution

In 1999, the Texas legislature adopted the Texas Electric Choice Plan (Texas electric restructuring law) that led to the restructuring of certain integrated electric utilities operating within Texas. Pursuant to that legislation, integrated electric utilities operating within the Electric Reliability Council of Texas, Inc. (ERCOT) were required to unbundle their integrated operations into separate retail sales, power generation and transmission and distribution companies. The legislation also required that the prices for wholesale generation and retail electric sales be unregulated, but services by companies providing transmission and distribution service, such as CenterPoint Houston, would remain regulated by the Public Utility Commission of Texas (Texas Utility Commission). The legislation provided for a transition period to move to the new market structure and provided a true-up mechanism for the formerly integrated electric utilities to recover stranded and certain other costs resulting from the transition to competition. Those costs were recoverable after approval by the Texas Utility Commission either through the issuance of securitization bonds or through the implementation of a competition transition charge (CTC) as a rider to the utility's tariff.

CenterPoint Houston is a transmission and distribution electric utility that operates wholly within the state of Texas. Neither CenterPoint Houston nor any other subsidiary of CenterPoint Energy makes retail or wholesale sales of electric energy, or owns or operates any electric generating facilities.

Electric Transmission

On behalf of retail electric providers (REPs), CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers taking power at or above 69 kilovolts (kV) in locations throughout CenterPoint Houston's certificated service territory. CenterPoint Houston constructs and maintains transmission facilities and provides transmission services under tariffs approved by the Texas Utility Commission.

Electric Distribution

In ERCOT, end users purchase their electricity directly from certificated REPs. CenterPoint Houston delivers electricity for REPs in its certificated service area by carrying lower-voltage power from the substation to the retail electric customer. CenterPoint Houston's distribution network receives electricity from the transmission grid through power distribution substations and delivers electricity to end users through distribution feeders. CenterPoint Houston's operations include construction and maintenance of distribution facilities, metering services, outage response services and call center operations. CenterPoint Houston provides distribution services under tariffs approved by the Texas Utility Commission. Texas Utility Commission rules and market protocols govern the commercial operations of distribution companies and other market participants. Rates for these existing services are established pursuant to rate proceedings conducted before municipalities that have original jurisdiction and the Texas Utility Commission.

ERCOT Market Framework

CenterPoint Houston is a member of ERCOT. ERCOT serves as the regional reliability coordinating council for member electric power systems in Texas. ERCOT membership is open to consumer groups, investor and municipally-owned electric utilities, rural electric cooperatives, independent generators, power marketers, river authorities and REPs. The ERCOT market includes most of the State of Texas, other than a portion of the panhandle, portions of the eastern part of the state bordering Arkansas and Louisiana and the area in and around El Paso. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation's largest power markets. The ERCOT market included available generating capacity of approximately 76,000 megawatts (MW) at December 31, 2010. There are only limited direct current interconnections between the ERCOT market and other power markets in the United States and Mexico.

The ERCOT market operates under the reliability standards set by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC). These reliability standards are administered by the Texas Regional Entity (TRE), a functionally independent division of ERCOT. The Texas Utility Commission has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity supply across the state's main interconnected power transmission grid. The ERCOT independent system operator (ERCOT ISO) is responsible for operating the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers. Unlike certain other regional power markets, the ERCOT market is not a centrally dispatched power pool, and the ERCOT ISO does not procure energy on behalf of its members other than to maintain the reliable operations of the transmission system. Members who sell and purchase power are responsible for contracting sales and purchases of power bilaterally. The ERCOT ISO also serves as agent for procuring ancillary services for those members who elect not to provide their own ancillary services.

CenterPoint Houston's electric transmission business, along with those of other owners of transmission facilities in Texas, supports the operation of the ERCOT ISO. The transmission business has planning, design, construction, operation and maintenance responsibility for the portion of the transmission grid and for the load-serving substations it owns, primarily within its certificated area. CenterPoint Houston participates with the ERCOT ISO and other ERCOT utilities to plan, design, obtain regulatory approval for and construct new transmission lines necessary to increase bulk power transfer capability and to remove existing constraints on the ERCOT transmission grid.

Recovery of True-Up Balance

The Texas electric restructuring law substantially revised the regulatory structure governing electric utilities in order to allow retail competition for electric customers beginning in January 2002. The Texas electric restructuring law required the Texas Utility Commission to conduct a "true-up" proceeding to determine CenterPoint Houston's stranded costs and certain other costs resulting from the transition to a competitive retail electric market and to provide for its recovery of those costs.

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas electric restructuring law. In December 2004, the Texas Utility Commission issued its final order (True-Up Order) allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and provided for adjustment of the amount to be recovered to include interest on the balance until recovery, along with the principal portion of additional excess mitigation credits (EMCs) returned to customers after August 31, 2004 and certain other adjustments.

CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, that court issued its judgment on the various appeals. In its judgment, the district court:

- reversed the Texas Utility Commission's ruling that had denied CenterPoint Houston recovery of a portion of the capacity auction true-up amounts;

- reversed the Texas Utility Commission's ruling that precluded CenterPoint Houston from recovering the interest component of the EMCs paid to REPs; and

- affirmed the True-Up Order in all other respects.

The district court's decision would have had the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston's initial request.

CenterPoint Houston and other parties appealed the district court's judgment to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court's judgment to the extent it restored the capacity auction true-up amounts;

- reversed the district court's judgment to the extent it upheld the Texas Utility Commission's decision to allow CenterPoint Houston to recover EMCs paid to its former affiliate Reliant Energy, Inc. (Reliant Energy, Inc., formerly known as Reliant Resources, Inc., changed its name in 2009 to "RRI Energy, Inc." in connection with the sale of its Texas retail electric business, and again in December 2010 to "GenOn Energy, Inc." in connection with the merger of one of its wholly owned subsidiaries with Mirant Corporation. For convenience, we refer to this company as "RRI" in the context of discussing transactions relating to our formation, our pending true-up appeal and other historical matters, and as "GenOn" in the present and future context, unless stated otherwise.);

- ordered that the tax normalization issue described below be remanded to the Texas Utility Commission as requested by the Texas Utility Commission; and

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- affirmed the district court's judgment in all other respects.

In April 2008, the court of appeals denied all motions for rehearing and reissued substantially the same opinion as it had rendered in December 2007.

In June 2008, CenterPoint Houston petitioned the Texas Supreme Court for review of the court of appeals decision. In its petition, CenterPoint Houston seeks reversal of the parts of the court of appeals decision that (i) denied recovery of EMCs paid to RRI, (ii) denied recovery of the capacity auction true-up amounts allowed by the district court, (iii) affirmed the Texas Utility Commission's rulings that denied recovery of approximately $378 million related to depreciation and (iv) affirmed the Texas Utility Commission's refusal to permit CenterPoint Houston to utilize the partial stock valuation methodology for determining the market value of its former generation assets. Two other petitions for review were filed with the Texas Supreme Court by other parties to the appeal. In those petitions parties contend that (i) the Texas Utility Commission was without authority to fashion the methodology it used for valuing the former generation assets after it had determined that CenterPoint Houston could not use the partial stock valuation method, (ii) in fashioning the method it used for valuing the former generating assets, the Texas Utility Commission deprived parties of their due process rights and an opportunity to be heard, (iii) the net book value of the generating assets should have been adjusted downward due to the impact of a purchase option that had been granted to RRI, (iv) CenterPoint Houston should not have been permitted to recover construction work in progress balances without proving those amounts in the manner required by law and (v) the Texas Utility Commission was without authority to award interest on the capacity auction true-up award.

In June 2009, the Texas Supreme Court granted the petitions for review of the court of appeals decision. Oral argument before the court was held in October 2009. Although we and CenterPoint Houston believe that CenterPoint Houston's true-up request is consistent with applicable statutes and regulations and, accordingly, that it is reasonably possible that it will be successful in its appeal to the Texas Supreme Court, we can provide no assurance as to the ultimate court rulings on the issues to be considered in the appeal or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue described below.

To reflect the impact of the True-Up Order, in 2004 and 2005, we recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in our consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of further review by the Texas Supreme Court, we anticipate that we would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue described below, but could range from $190 million to $440 million (pre-tax) plus interest subsequent to December 31, 2010.

In the True-Up Order, the Texas Utility Commission reduced CenterPoint Houston's stranded cost recovery by approximately $146 million, which was included in the extraordinary loss discussed above, to reflect the present value of certain deferred tax benefits associated with its former electric generation assets. We believe that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 that would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, the IRS subsequently withdrew those proposed normalization regulations and, in March 2008, adopted final regulations that would not permit utilities like CenterPoint Houston to pass the tax benefits back to customers without creating normalization violations. In addition, we received a Private Letter Ruling (PLR) from the IRS in August 2007, prior to adoption of the final regulations, that confirmed that the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations with respect to the ADITC and EDFIT.

If the Texas Utility Commission’s order relating to the ADITC reduction is not reversed or otherwise modified on remand so as to eliminate the normalization violation, the IRS could require us to pay an amount equal to CenterPoint Houston’s unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. Such treatment, if required by the IRS, could have a material adverse impact on our results of operations, financial condition and cash flows in addition to any potential loss resulting from final resolution of the True-Up Order. Following the adoption by the IRS of the final regulations described above, the Texas Utility Commission requested, and the court of appeals ordered, that this issue be remanded to that commission for further consideration. No party has challenged that order by the court of appeals although the Texas Supreme Court has the authority to consider all aspects of the rulings above, not just those challenged specifically by the appellants. We and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate and administrative process. Although the Texas Utility Commission has requested that this issue be remanded to it by the courts and has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation, no prediction can be made as to the ultimate action the Texas Utility Commission may take on this issue on remand.

The Texas electric restructuring law allowed the amounts awarded to CenterPoint Houston in the Texas Utility Commission's True-Up Order to be recovered either through securitization or through implementation of a CTC or both. Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed by a Travis County district court, in December 2005, a new special purpose subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84% to 5.30% and final maturity dates ranging from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

In July 2005, CenterPoint Houston received an order from the Texas Utility Commission allowing it to implement a CTC designed to collect the remaining $596 million from the True-Up Order over 14 years plus interest at an annual rate of 11.075% (CTC Order). The CTC Order authorized CenterPoint Houston to impose a charge on REPs to recover the portion of the true-up balance not recovered through a financing order. The CTC Order also allowed CenterPoint Houston to collect approximately $24 million of rate case expenses over three years without a return through a separate tariff rider (Rider RCE). CenterPoint Houston implemented the CTC and Rider RCE effective September 13, 2005 and began recovering approximately $620 million. The return on the CTC portion of the true-up balance was included in CenterPoint Houston's tariff-based revenues beginning September 13, 2005. Effective August 1, 2006, the interest rate on the unrecovered balance of the CTC was reduced from 11.075% to 8.06% pursuant to a revised rule adopted by the Texas Utility Commission in June 2006. Recovery of rate case expenses under Rider RCE was completed in September 2008.

Certain parties appealed the CTC Order to a district court in Travis County. In May 2006, the district court issued a judgment reversing the CTC Order in three respects. First, the court ruled that the Texas Utility Commission had improperly relied on provisions of its rule dealing with the interest rate applicable to CTC amounts. The district court reached that conclusion based on its belief that the Texas Supreme Court had previously invalidated that entire section of the rule. The 11.075% interest rate in question was applicable from the implementation of the CTC Order on September 13, 2005 until August 1, 2006, the effective date of the implementation of a new CTC in compliance with the revised rule discussed above. Second, the district court reversed the Texas Utility Commission's ruling that allows CenterPoint Houston to recover through Rider RCE the costs (approximately $5 million) for a panel appointed by the Texas Utility Commission in connection with the valuation of electric generation assets. Finally, the district court accepted the contention of one party that the CTC should not be allocated to retail customers that have switched to new on-site generation. The Texas Utility Commission and CenterPoint Houston appealed the district court's judgment to the Texas Third Court of Appeals, and in July 2008, the court of appeals reversed the district court's judgment in all respects and affirmed the Texas Utility Commission's order. Two parties appealed the court of appeals decision to the Texas Supreme Court and on October 22, 2010, the Texas Supreme Court issued an opinion affirming the judgment of the court of appeals. The Texas Supreme Court's decision did not have an impact on our or CenterPoint Houston's financial position, results of operations or cash flows.

During the 2007 legislative session, the Texas legislature amended statutes prescribing the types of true-up balances that can be securitized by utilities and authorized the issuance of transition bonds to recover the balance of the CTC. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of the remaining balance of the CTC, adjusted to refund certain unspent environmental retrofit costs and to recover the amount of the final fuel reconciliation settlement. CenterPoint Houston reached substantial agreement with other parties to this proceeding, and a financing order was approved by the Texas Utility Commission in September 2007. In February 2008, pursuant to the financing order, a new special purpose subsidiary of CenterPoint Houston issued approximately $488 million of transition bonds in two tranches with interest rates of 4.192% and 5.234% and final maturity dates of February 2020 and February 2023, respectively. Contemporaneously with the issuance of those bonds, the CTC was terminated and a transition charge was implemented. During the year ended December 31, 2008, CenterPoint Houston recognized approximately $5 million in operating income from the CTC.

As of December 31, 2010, we have not recognized an allowed equity return of $178 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates. During the years ended December 31, 2008, 2009 and 2010, CenterPoint Houston recognized approximately $13 million, $13 million and $15 million, respectively, of the allowed equity return.

Hurricane Ike

CenterPoint Houston's electric delivery system suffered substantial damage as a result of Hurricane Ike, which struck the upper Texas coast in September 2008. CenterPoint Houston deferred the system restoration costs as management believed it was probable that such costs would be recovered through the regulatory process. As a result, system restoration costs did not affect our or CenterPoint Houston's reported operating income for 2008 or 2009.

CenterPoint Houston filed with the Texas Utility Commission an application for review and approval for recovery of approximately $678 million, including approximately $608 million in system restoration costs identified as of the end of February 2009, plus $2 million in regulatory expenses, $13 million in certain debt issuance costs and $55 million in incurred and projected carrying costs calculated through August 2009. In July 2009, CenterPoint Houston reached a settlement agreement with the parties to the proceeding. Under that settlement agreement, CenterPoint Houston was entitled to recover a total of $663 million in costs relating to Hurricane Ike, along with carrying costs from September 1, 2009 until system restoration bonds were issued. The Texas Utility Commission issued an order in August 2009 approving the settlement agreement and authorizing recovery of $663 million, of which $643 million was attributable to distribution service and eligible for securitization and the remaining $20 million was attributable to transmission service and eligible for recovery through the existing mechanisms established to recover transmission costs.

In August 2009, the Texas Utility Commission issued a financing order allowing CenterPoint Houston to securitize $643 million in distribution service costs plus carrying charges from September 1, 2009 through the date the system restoration bonds were issued, as well as certain up-front qualified costs capped at approximately $6 million. In November 2009, CenterPoint Houston issued approximately $665 million of system restoration bonds through its CenterPoint Energy Restoration Bond Company, LLC subsidiary with interest rates of 1.833% to 4.243% and final maturity dates ranging from February 2016 to August 2023. The bonds will be repaid over time through a charge imposed on customers.

In accordance with the financing order, CenterPoint Houston also placed a separate customer credit in effect when the storm restoration bonds were issued. That credit (ADFIT Credit) is applied to customers' bills while the bonds are outstanding to reflect the benefit of accumulated deferred federal income taxes (ADFIT) associated with the storm restoration costs (including a carrying charge of 11.075%). The beginning balance of the ADFIT related to storm restoration costs was approximately $207 million and will decline over the life of the system restoration bonds as taxes are paid on the system restoration tariffs. The ADFIT Credit reduced operating income in 2010 by approximately $23 million.

Customers

CenterPoint Houston serves nearly all of the Houston/Galveston metropolitan area. CenterPoint Houston's customers consist of 99 REPs, which sell electricity to over two million metered customers in CenterPoint Houston's certificated service area, and municipalities, electric cooperatives and other distribution companies located outside CenterPoint

Houston's certificated service area. Each REP is licensed by, and must meet minimum creditworthiness criteria established by, the Texas Utility Commission.

Sales to REPs that are subsidiaries of NRG Retail LLC (NRG Retail) represented approximately 48%, 44% and 38% of CenterPoint Houston's transmission and distribution revenues in 2008, 2009 and 2010, respectively. Sales to subsidiaries of TXU Energy Retail Company LLC (TXU Energy Retail) represented approximately 11%, 12%

and 12% of CenterPoint Houston's transmission and distribution revenues in 2008, 2009 and 2010, respectively. CenterPoint Houston's billed receivables balance from REPs as of December 31, 2010 was $138 million. Approximately 33% and 13% of this amount was owed by subsidiaries of NRG Retail and TXU Energy Retail, respectively. CenterPoint Houston does not have long-term contracts with any of its customers. It operates using a continuous billing cycle, with meter readings being conducted and invoices being distributed to REPs each business day.

Advanced Metering System and Distribution Grid Automation (Intelligent Grid)

In December 2008, CenterPoint Houston received approval from the Texas Utility Commission to deploy an advanced metering system (AMS) across its service territory over the next five years. CenterPoint Houston began installing advanced meters in March 2009. This innovative technology should encourage greater energy conservation by giving Houston-area electric consumers the ability to better monitor and manage their electric use and its cost in near real time. CenterPoint Houston is currently recovering the cost for the AMS through a monthly surcharge to all REPs over 12 years. The surcharge for each residential consumer for the first 24 months, which began in February 2009, was $3.24 per month. Beginning in February 2011, the surcharge was reduced to $3.05 per month. These amounts are subject to upward or downward adjustment in future proceedings to reflect actual costs incurred and to address required changes in scope.

CenterPoint Houston is also pursuing deployment of an electric distribution grid automation strategy that involves the implementation of an "Intelligent Grid" (IG) which would make use of CenterPoint Houston's facilities to provide on-demand data and information about the status of facilities on its system. Although this technology is still in the developmental stage, CenterPoint Houston believes it has the potential to provide a significant improvement in grid planning, operations, maintenance and customer service for the CenterPoint Houston distribution system. These improvements are expected to contribute to fewer and shorter outages, better customer service, improved operations costs, improved security and more effective use of our workforce. We expect to include the costs of the deployment in future rate proceedings before the Texas Utility Commission.

In October 2009, the U.S. Department of Energy (DOE) notified CenterPoint Houston that it had been selected for a $200 million grant for its AMS and IG projects. In March 2010, CenterPoint Houston and the DOE completed negotiations and finalized the agreement. Under the terms of the agreement, the DOE has agreed to reimburse CenterPoint Houston for 50% of its eligible costs until the total amount of the grant has been paid. Through December 31, 2010, CenterPoint Houston has requested $100 million of grant funding from the DOE, of which $90 million had been received. CenterPoint Houston estimates that capital expenditures of approximately $645 million for the installation of the advanced meters and corresponding communication and data management systems will be incurred over the deployment period. CenterPoint Houston is using $150 million of the grant funding to accelerate completion of its current deployment of advanced meters to 2012, instead of 2014 as originally scheduled. CenterPoint Houston will use the other $50 million from the grant to begin deployment of an IG in a portion of its service territory over the next three years. It is expected that the portion of the IG project subject to funding by the DOE will cost approximately $115 million.

In March 2010, the IRS announced through the issuance of Revenue Procedure 2010-20 that it was providing a safe harbor to corporations that receive a Smart Grid Investment Grant. The IRS stated that it would not challenge a corporation's treatment of the grant as a non-taxable non-shareholder contribution to capital as long as the corporation properly reduced the tax basis of specified property acquired.

Competition

There are no other electric transmission and distribution utilities in CenterPoint Houston's service area. In order for another provider of transmission and distribution services to provide such services in CenterPoint Houston's territory, it would be required to obtain a certificate of convenience and necessity from the Texas Utility Commission and, depending on the location of the facilities, may also be required to obtain franchises from one or more municipalities. We know of no other party intending to enter this business in CenterPoint Houston's service area at this time.

Seasonality

A significant portion of CenterPoint Houston's revenues is derived from rates that it collects from each REP based on the amount of electricity it delivers on behalf of such REP. Thus, CenterPoint Houston's revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues being higher during the warmer months.

Properties

All of CenterPoint Houston's properties are located in Texas. Its properties consist primarily of high voltage electric transmission lines and poles, distribution lines, substations, service wires and meters. Most of CenterPoint Houston's transmission and distribution lines have been constructed over lands of others pursuant to easements or along public highways and streets as permitted by law.

All real and tangible properties of CenterPoint Houston, subject to certain exclusions, are currently subject to:

- the lien of a Mortgage and Deed of Trust (the Mortgage) dated November 1, 1944, as supplemented; and

- the lien of a General Mortgage (the General Mortgage) dated October 10, 2002, as supplemented, which is junior to the lien of the Mortgage.

As of December 31, 2010, CenterPoint Houston had approximately $2.5 billion aggregate principal amount of general mortgage bonds outstanding under the General Mortgage, including (a) $290 million held in trust to secure pollution control bonds that are not reflected on our consolidated financial statements because we are both the obligor on the bonds and the owner of the bonds, (b) an additional approximately $237 million held in trust to secure pollution control bonds for which we are obligated and (c) approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had approximately $253 million aggregate principal amount of first mortgage bonds outstanding under the Mortgage, including approximately $151 million held in trust to secure certain pollution control bonds for which we are obligated. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $2.3 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2010. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

Electric Lines — Overhead. As of December 31, 2010, CenterPoint Houston owned 27,842 pole miles of overhead distribution lines and 3,728 circuit miles of overhead transmission lines, including 422 circuit miles operated at 69,000 volts, 2,090 circuit miles operated at 138,000 volts and 1,216 circuit miles operated at 345,000 volts.

Electric Lines — Underground. As of December 31, 2010, CenterPoint Houston owned 20,390 circuit miles of underground distribution lines and 26 circuit miles of underground transmission lines, including 2 circuit miles operated at 69,000 volts and 24 circuit miles operated at 138,000 volts.

Substations. As of December 31, 2010, CenterPoint Houston owned 233 major substation sites having a total installed rated transformer capacity of 52,938 megavolt amperes.

Service Centers. CenterPoint Houston operates 14 regional service centers located on a total of 291 acres of land. These service centers consist of office buildings, warehouses and repair facilities that are used in the business of transmitting and distributing electricity.

Franchises

CenterPoint Houston holds non-exclusive franchises from the incorporated municipalities in its service territory. In exchange for the payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 50 years.

Natural Gas Distribution

CERC Corp.'s natural gas distribution business (Gas Operations) engages in regulated intrastate natural gas sales to, and natural gas transportation for, approximately 3.3 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. The largest metropolitan areas served in each state by Gas Operations are Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. In 2010, approximately 42% of Gas Operations' total throughput was to residential customers and approximately 58% was to commercial and industrial customers.

The table below reflects the number of natural gas distribution customers by state as of December 31, 2010:

	Residential	Commercial/ Industrial	Total Customers
Arkansas	390,668	48,033	438,701
Louisiana	232,135	17,347	249,482
Minnesota	738,868	67,489	806,357
Mississippi	109,608	12,683	122,291
Oklahoma	93,388	10,620	104,008
Texas	1,451,666	90,719	1,542,385
Total Gas Operations	3,016,333	246,891	3,263,224

Gas Operations also provides unregulated services consisting of heating, ventilating and air conditioning (HVAC) equipment and appliance repair, and sales of HVAC, hearth and water heating equipment in Minnesota.

The demand for intrastate natural gas sales to residential customers and natural gas sales and transportation for commercial and industrial customers is seasonal. In 2010, approximately 71% of the total throughput of Gas Operations' business occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during those periods.

Supply and Transportation. In 2010, Gas Operations purchased virtually all of its natural gas supply pursuant to contracts with remaining terms varying from a few months to four years. Major suppliers in 2010 included BP Canada Energy Marketing Corp. (25.6% of supply volumes), ConocoPhillips Company (8.3%), Tenaska Marketing Ventures (6.8%), Kinder Morgan (6.3%), Oneok Energy Marketing Company (4.7%), and Cargill, Inc. (4.6%). Numerous other suppliers provided the remaining 43.7% of Gas Operations' natural gas supply requirements. Gas Operations transports its natural gas supplies through various intrastate and interstate pipelines, including those owned by our other subsidiaries, under contracts with remaining terms, including extensions, varying from one to twelve years. Gas Operations anticipates that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

Gas Operations actively engages in commodity price stabilization pursuant to annual gas supply plans presented to and/or filed with each of its state regulatory authorities. These price stabilization activities include use of storage gas, contractually establishing fixed prices with our physical gas suppliers and utilizing financial derivative instruments to achieve a variety of pricing structures (e.g., fixed price, costless collars and caps). Its gas supply plans generally call for 25-50% of winter supplies to be hedged in some fashion.

Generally, the regulations of the states in which Gas Operations operates allow it to pass through changes in the cost of natural gas, including gains and losses on financial derivatives associated with the index-priced physical supply, to its customers under purchased gas adjustment provisions in its tariffs. Depending upon the jurisdiction, the purchased gas adjustment factors are updated periodically, ranging from monthly to semi-annually, using estimated gas costs. The changes in the cost of gas billed to customers are subject to review by the applicable regulatory bodies.

Gas Operations uses various third-party storage services or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather and may also supplement contracted supplies and storage from time to time with stored liquefied natural gas and propane-air plant production.

Gas Operations owns and operates an underground natural gas storage facility with a capacity of 7.0 billion cubic feet (Bcf). It has a working capacity of 2.0 Bcf available for use during a normal heating season and a maximum daily withdrawal rate of 50 million cubic feet (MMcf). It also owns nine propane-air plants with a total production rate of 200,000 Dekatherms (DTH) per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf natural gas equivalent). It owns a liquefied natural gas plant facility with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf natural gas equivalent) and a production rate of 72,000 DTH per day.

On an ongoing basis, Gas Operations enters into contracts to provide sufficient supplies and pipeline capacity to meet its customer requirements. However, it is possible for limited service disruptions to occur from time to time due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time, or prices may increase rapidly in response to temporary supply constraints or other factors.

Gas Operations has entered into various asset management agreements associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, these asset management agreements are contracts between Gas Operations and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, Gas Operations agreed to release transportation and storage capacity to other parties to manage gas storage, supply and delivery arrangements for Gas Operations and to use the released capacity for other purposes when it is not needed for Gas Operations. Gas Operations is compensated by the asset manager through payments made over the life of the agreements based in part on the results of the asset optimization. Gas Operations has received approval from the state regulatory commissions in Arkansas, Louisiana, Mississippi and Oklahoma to retain a share of the asset management agreement proceeds, although the percentage of payments to be retained by Gas Operations varies based on the jurisdiction, with the majority of the payments to benefit customers. The agreements have varying terms, the longest of which expires in 2016.

Assets

As of December 31, 2010, Gas Operations owned approximately 71,000 linear miles of natural gas distribution mains, varying in size from one-half inch to 24 inches in diameter. Generally, in each of the cities, towns and rural areas served by Gas Operations, it owns the underground gas mains and service lines, metering and regulating equipment located on customers' premises and the district regulating equipment necessary for pressure maintenance. With a few exceptions, the measuring stations at which Gas Operations receives gas are owned, operated and maintained by others, and its distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on land owned by suppliers.

Competition

Gas Operations competes primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other gas distributors and marketers also compete directly for gas sales to end-users. In addition, as a result of federal regulations affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass Gas Operations' facilities and market and sell and/or transport natural gas directly to commercial and industrial customers.

Competitive Natural Gas Sales and Services

CERC offers variable and fixed-priced physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities through CenterPoint Energy Services, Inc. (CES) and its subsidiary, CenterPoint Energy Intrastate Pipelines, LLC (CEIP).

In 2010, CES marketed approximately 548 Bcf of natural gas, related energy services and transportation to approximately 12,200 customers (including approximately 7 Bcf to affiliates). CES customers vary in size from small commercial customers to large utility companies in the central and eastern regions of the United States. The business has three operational divisions: wholesale, retail and intrastate pipelines, which are further described below.

Wholesale Division. CES offers a portfolio of physical delivery services and financial products designed to meet wholesale customers' supply and price risk management needs. These customers are served directly through interconnects with various interstate and intrastate pipeline companies, and include gas utilities, large industrial customers and electric generation customers. This division includes the supply function for the procurement of natural gas and the management and optimization of transportation and storage assets for CES.

Retail Division. CES offers a variety of natural gas management services to smaller commercial and industrial customers, municipalities, educational institutions and hospitals, whose facilities are typically located downstream of natural gas distribution utility city gate stations. These services include load forecasting, supply acquisition, daily swing volume management, invoice consolidation, storage asset management, firm and interruptible transportation administration and forward price management. CES manages transportation contracts and energy supply for retail customers in 17 states.

Intrastate Pipeline Division. CEIP provides transportation services to shippers and end-users and contracts out approximately 2.3 Bcf of storage at its Pierce Junction facility in Texas.

CES currently transports natural gas on over 40 interstate and intrastate pipelines within states located throughout the central and eastern United States. CES maintains a portfolio of natural gas supply contracts and firm transportation and storage agreements to meet the natural gas requirements of its customers. CES aggregates supply from various producing regions and offers contracts to buy natural gas with terms ranging from one month to over five years. In addition, CES actively participates in the spot natural gas markets in an effort to balance daily and monthly purchases and sales obligations. Natural gas supply and transportation capabilities are leveraged through contracts for ancillary services including physical storage and other balancing arrangements.

As described above, CES offers its customers a variety of load following services. In providing these services, CES uses its customers' purchase commitments to forecast and arrange its own supply purchases, storage and transportation services to serve customers' natural gas requirements. As a result of the variance between this forecast activity and the actual monthly activity, CES will either have too much supply or too little supply relative to its customers' purchase commitments. These supply imbalances arise each month as customers' natural gas requirements are scheduled and corresponding natural gas supplies are nominated by CES for delivery to those customers. CES' processes and risk control environment are designed to measure and value imbalances on a real-time basis to ensure that CES' exposure to commodity price risk is kept to a minimum. The value assigned to these imbalances is calculated daily and is known as the aggregate Value at Risk (VaR).

Our risk control policy, which is overseen by our Risk Oversight Committee, defines authorized and prohibited trading instruments and trading limits. CES is a physical marketer of natural gas and uses a variety of tools, including pipeline and storage capacity, financial instruments and physical commodity purchase contracts to support its sales. The CES business optimizes its use of these various tools to minimize its supply costs and does not engage in proprietary or speculative commodity trading. The VaR limits within which CES operates, a $4 million maximum, are consistent with CES' operational objective of matching its aggregate sales obligations (including the swing associated with load following services) with its supply portfolio in a manner that minimizes its total cost of supply. In 2010, CES' VaR averaged $0.7 million with a high of $1.7 million.

Assets

CEIP owns and operates approximately 233 miles of intrastate pipeline in Louisiana and Texas and holds storage facilities of approximately 2.3 Bcf in Texas under long-term leases. In addition, CES leases transportation capacity of approximately 0.9 Bcf per day on various interstate and intrastate pipelines and approximately 15.4 Bcf of storage to service its customer base.

Competition

CES competes with regional and national wholesale and retail gas marketers including the marketing divisions of natural gas producers and utilities. In addition, CES competes with intrastate pipelines for customers and services in its market areas.

Interstate Pipelines

CERC's pipelines business operates interstate natural gas pipelines with gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. CERC's interstate pipeline operations are primarily conducted by two wholly owned subsidiaries that provide gas transportation and storage services primarily to industrial customers and local distribution companies:

- CenterPoint Energy Gas Transmission Company, LLC (CEGT) is an interstate pipeline that provides natural gas transportation, natural gas storage and pipeline services to customers principally in Arkansas, Louisiana, Oklahoma and Texas; and

- CenterPoint Energy-Mississippi River Transmission, LLC (MRT) is an interstate pipeline that provides natural gas transportation, natural gas storage and pipeline services to customers principally in Arkansas and Missouri.

The rates charged by CEGT and MRT for interstate transportation and storage services are regulated by the FERC. CERC's interstate pipelines business operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

In 2010, approximately 16% of CEGT and MRT's total operating revenue was attributable to services provided to Gas Operations, an affiliate, and approximately 7% was attributable to services provided to Laclede Gas Company (Laclede), an unaffiliated distribution company, that provides natural gas utility service to the greater St. Louis metropolitan area in Illinois and Missouri. Services to Gas Operations and Laclede are provided under several long-term firm storage and transportation agreements. The primary term of MRT's firm transportation and storage contracts with Laclede will expire in 2013. In May 2010, Gas Operations and CEGT reached an agreement to renew the contracts for terms extending through March 31, 2021. All applicable regulatory approvals have been received.

Carthage to Perryville. In February 2010, CEGT completed the expansion of the capacity of its Carthage to Perryville pipeline to approximately 1.9 Bcf per day. The 274 MMcf per day expansion includes new compressor units at two of CEGT's existing stations.

Southeast Supply Header, LLC. CenterPoint Southeastern Pipelines Holding, LLC, a wholly-owned subsidiary of CERC, owns a 50% interest in Southeast Supply Header, LLC (SESH). SESH owns a 1.0 Bcf per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama. The pipeline was placed into service in September 2008. The rates charged by SESH for interstate transportation services are regulated by the FERC. A wholly-owned, indirect subsidiary of Spectra Energy Corp. owns the remaining 50% interest in SESH.

Assets

CERC's interstate pipelines business currently owns and operates approximately 8,000 miles of natural gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. CERC's interstate pipeline business also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.3 Bcf and a combined working gas capacity of approximately 59 Bcf. CERC's interstate pipeline business also owns a 10% interest in the Bistineau storage facility located in Bienville Parish, Louisiana, with the remaining interest owned and operated by Gulf South Pipeline Company, LP. CERC's interstate pipeline business' storage capacity in the Bistineau facility is 8 Bcf of working gas with 100 MMcf per day of deliverability. Most storage operations are in north Louisiana and Oklahoma.

Competition

CERC's interstate pipelines business competes with other interstate and intrastate pipelines in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service, and flexibility and reliability of service. CERC's interstate pipelines business competes indirectly with other forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price, but environmental considerations have grown in importance when consumers consider alternative forms of energy. Changes in the availability of energy and pipeline capacity, the level of business activity, conservation and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas in areas we serve and the level of competition for transportation and storage services.

Field Services

CERC’s field services business operates gas gathering, treating and processing facilities and also provides operating and technical services and remote data monitoring and communication services.

CERC’s field services operations are conducted by a wholly owned subsidiary, CenterPoint Energy Field Services, LLC. (CEFS). CEFS provides natural gas gathering and processing services for certain natural gas fields in the Mid-continent region of the United States that interconnect with CEGT’s and MRT’s pipelines, as well as other interstate and intrastate pipelines. CEFS gathers approximately 2.0 Bcf per day of natural gas and, either directly or through its 50% interest in a joint venture, processes in excess of 260 MMcf per day of natural gas along its gathering system. CEFS, through its ServiceStar operating division, provides remote data monitoring and communications services to affiliates and third parties.

CERC's field services business operations may be affected by changes in the demand for natural gas and natural gas liquids (NGLs), the available supply and relative price of natural gas and NGLs in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

Magnolia Gathering System. In September 2009, CEFS 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. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Magnolia Gathering System) from Encana and Shell in northwest Louisiana. Each of the agreements includes acreage dedication and volume commitments for which CEFS has exclusive rights to gather Shell’s and Encana’s natural gas production.

During the year ended December 31, 2010, CEFS substantially completed the construction and initial expansion of the Magnolia Gathering System in order to permit the system to gather and treat up to 700 MMcf per day of natural gas, with only well connects remaining. As of December 31, 2010, CEFS had spent approximately $310 million on the original project scope, including the purchase of the original facilities and is in the second year of the 10-year 700 MMcf per day volume commitment made by Shell and Encana.

Pursuant to an expansion election made by Encana and Shell in March 2010, CEFS expanded the Magnolia Gathering System to increase its gathering and treating capacity by an additional 200 MMcf per day, increasing the aggregate capacity of the system to 900 MMcf per day. As of December 31, 2010, CEFS had spent approximately $47 million on the expansion. The expansion was completed and placed into service in February, 2011 at a total cost of approximately $52 million. The 200 MMcf per day incremental volume commitment made by Shell and Encana began contemporaneously with the completion of the expansion.

Under the long-term agreements, Encana or Shell may elect to require CEFS to expand the capacity of the Magnolia Gathering System by up to an additional 800 MMcf per day, bringing the total system capacity to 1.7 Bcf per day. CEFS estimates that the cost to expand the capacity of the Magnolia Gathering System by an additional 800 MMcf per day would be as much as $240 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Olympia Gathering System. In April 2010, CEFS entered into additional long-term agreements with Encana and Shell to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Olympia Gathering System) from Encana and Shell in northwest Louisiana.

Under the terms of the agreements, CEFS is expanding the Olympia Gathering System in order to permit the system to gather and treat up to 600 MMcf per day of natural gas. As of December 31, 2010, CEFS had spent approximately $340 million on the 600 MMcf per day project, including the purchase of the original facilities, and expects to incur up to an additional $85 million to complete this expansion. CEFS expects the full 600 MMcf per day of capacity to be in service in the first quarter of 2011. CEFS is in the first year of the 10-year 600 MMcf per day volume commitment made by Shell and Encana .

Under the long-term agreements, Encana and Shell may elect to require CEFS to expand the capacity of the Olympia Gathering System by up to an additional 520 MMcf per day, bringing the total system capacity to 1.1 Bcf per day. CEFS estimates that the cost to expand the capacity of the Olympia Gathering System by an additional 520 MMcf per day would be as much as $200 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system’s capacity.

Waskom Gas Processing Company. CenterPoint Energy Gas Processing Company, a wholly-owned, indirect subsidiary of CERC, owns a 50% general partnership interest in Waskom Gas Processing Company (Waskom). Waskom owns a natural gas processing plant and natural gas gathering assets located in East Texas. The plant is capable of processing approximately 285 MMcf per day of natural gas. The gathering assets are capable of gathering approximately 75 MMcf per day of natural gas.

Assets

CERC’s field services business owns and operates approximately 3,800 miles of gathering lines and processing plants that collect, treat and process natural gas primarily from three regions located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Competition

CERC's field services business competes with other companies in the natural gas gathering, treating and processing business. The principal elements of competition are rates, terms of service and reliability of services. CERC's field services business competes indirectly with alternative forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price, but environmental considerations have grown in importance when consumers consider other forms of energy. Changes in the availability of energy and pipeline capacity, the level of business activity, conservation and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas in areas we serve and the level of competition for gathering, treating, and processing services. In addition, competition among forms of energy is affected by commodity pricing levels and influences the level of drilling activity and demand for our gathering operations.

Other Operations

Our Other Operations business segment includes office buildings and other real estate used in our business operations and other corporate operations that support all of our business operations.

Financial Information About Segments

For financial information about our segments, see Note 16 to our consolidated financial statements, which note is incorporated herein by reference.

REGULATION

We are subject to regulation by various federal, state and local governmental agencies, including the regulations described below.

Federal Energy Regulatory Commission

The FERC has jurisdiction under the Natural Gas Act and the Natural Gas Policy Act of 1978, as amended, to regulate the transportation of natural gas in interstate commerce and natural gas sales for resale in interstate commerce that are not first sales. The FERC regulates, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. The rates charged by interstate pipelines for interstate transportation and storage services are also regulated by the FERC. The Energy Policy Act of 2005 (Energy Act) expanded the FERC's authority to prohibit market manipulation in connection with FERC-regulated transactions and gave the FERC additional authority to impose significant civil and criminal penalties for statutory violations and violations of the FERC's rules or orders and also expanded criminal penalties for such violations. Our competitive natural gas sales and services subsidiary markets natural gas in interstate commerce pursuant to blanket authority granted by the FERC.

CERC's natural gas pipeline subsidiaries may periodically file applications with the FERC for changes in their generally available maximum rates and charges designed to allow them to recover their costs of providing service to customers (to the extent allowed by prevailing market conditions), including a reasonable rate of return. These rates are normally allowed to become effective after a suspension period and, in some cases, are subject to refund under applicable law until such time as the FERC issues an order on the allowable level of rates.

CenterPoint Houston is not a "public utility" under the Federal Power Act and, therefore, is not generally regulated by the FERC, although certain of its transactions are subject to limited FERC jurisdiction. The Energy Act conferred new jurisdiction and responsibilities on the FERC with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by CenterPoint Houston and other utilities within ERCOT. Under this authority, the FERC has designated the NERC as the Electric Reliability Organization (ERO) to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system (Electric Entities). The ERO and the FERC have authority to (a) impose fines and other sanctions on Electric Entities that fail to comply with approved standards and (b) audit compliance with approved standards. The FERC has approved the delegation by the NERC of authority for reliability in ERCOT to the TRE. CenterPoint Houston does not anticipate that the reliability standards proposed by the NERC and approved by the FERC will have a material adverse impact on its operations. To the extent that CenterPoint Houston is required to make additional expenditures to comply with these standards, it is anticipated that CenterPoint Houston will seek to recover those costs through the transmission charges that are imposed on all distribution service providers within ERCOT for electric transmission provided.

As a public utility holding company, under the Public Utility Holding Company Act of 2005, we and our subsidiaries are subject to reporting and accounting requirements and are required to maintain certain books and records and make them available for review by the FERC and state regulatory authorities in certain circumstances.

State and Local Regulation

Electric Transmission & Distribution

CenterPoint Houston conducts its operations pursuant to a certificate of convenience and necessity issued by the Texas Utility Commission that covers its present service area and facilities. The Texas Utility Commission and those municipalities that have retained original jurisdiction have the authority to set the rates and terms of service provided by CenterPoint Houston under cost of service rate regulation. CenterPoint Houston holds non-exclusive franchises from the incorporated municipalities in its service territory. In exchange for payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 50 years.

CenterPoint Houston’s distribution rates charged to REPs for residential customers are primarily based on amounts of energy delivered, whereas distribution rates for a majority of commercial and industrial customers are primarily based on peak demand. All REPs in CenterPoint Houston’s service area pay the same rates and other charges for transmission and distribution services. This regulated delivery charge includes the transmission and distribution rate (which includes municipal franchise fees), a system benefit fund fee imposed by the Texas electric restructuring law, a nuclear decommissioning charge associated with decommissioning the South Texas nuclear generating facility, an energy efficiency cost recovery charge, a surcharge related to the implementation of AMS and charges associated with securitization of regulatory assets, stranded costs and restoration costs relating to Hurricane Ike. Transmission rates charged to other distribution companies are based on amounts of energy transmitted under "postage stamp" rates that do not vary with the distance the energy is being transmitted. All distribution companies in ERCOT pay CenterPoint Houston the same rates and other charges for transmission services.

Recovery of True-Up Balance. For a discussion of CenterPoint Houston's true-up proceedings, see "— Our Business — Electric Transmission & Distribution — Recovery of True-Up Balance" above.

2010 Rate Proceeding. As required under the final order in its 2006 rate proceeding, in June 2010 CenterPoint Houston filed an application to change rates with the Texas Utility Commission and the cities in its service area, including cost data and other information supporting an annual increase of $106 million for delivery charges to the REPs that sell electricity to end-use customers in CenterPoint Houston's service territory that was offset by a reduction of other utility revenues, resulting in a $92 million requested annual revenue increase. The rate filing package also supported an annual increase of $18 million for wholesale transmission customers.

In the filing, CenterPoint Houston also requested reconciliation of its AMS costs incurred as of March 31, 2010, and revision of the estimated costs to complete the AMS project in order to reflect $150 million in funds from the $200 million DOE stimulus grant awarded to CenterPoint Houston and updated cost information. The reconciliation plan also requested that the duration of the residential AMS surcharge be shortened by six years from the original 12-year plan.

In its rate filing, CenterPoint Houston sought a return on equity of 11.25% and proposed that rates be based on a capital structure of 50% equity and 50% long-term debt.

Hearings concerning the rate filing concluded in October 2010, and a Proposal for Decision was issued by the presiding Administrative Law Judges. On February 3, 2011 the Texas Utility Commission voted on the various contested issues presented by the rate filing. The Texas Utility Commission has not yet issued a formal order implementing its decisions, and the order, once issued, will be subject to revision based on motions for rehearing by the parties to the proceeding and could be appealed to the Texas courts.

Based on the public deliberations and votes by the Commissioners, CenterPoint Houston anticipates that the order of the Texas Utility Commission will provide for a base rate increase for CenterPoint Houston of approximately $14.7 million per year for delivery charges to the REPs and a decrease to charges to wholesale transmission customers of $12.3 million per year. Further, the order is expected to provide a mechanism to track amounts for uncertain tax positions and provide for ultimate recovery of those costs.

The order is expected to be based on an authorized return on equity for CenterPoint Houston of 10%, a cost of debt of –6.74–%, a capital structure comprised of 55% debt and 45% common equity, and an overall rate of return of 8.21%. The decision also will implement CenterPoint Houston's request to reconcile costs incurred for the AMS project and to shorten the period for collecting the AMS surcharge from twelve to six years for residential customers in order to reflect the funds received from the DOE.

Based on CenterPoint Houston's understanding of the Texas Utility Commission's votes, CenterPoint Houston anticipates that annual operating income will be reduced by approximately $30 million from 2010 levels as a result of the Texas Utility Commission's decision. CenterPoint Houston expects that revised rates based on the Texas Utility Commission's decision will be implemented during the second quarter of 2011.

Other Rate Proceedings. In May 2009, CenterPoint Houston filed an application at the Texas Utility Commission seeking approval of certain estimated 2010 energy efficiency program costs, an energy efficiency performance bonus for 2008 programs, and carrying costs totaling approximately $10 million. The application sought to begin recovery of these costs through a surcharge effective July 1, 2010. In October 2009, the Texas Utility Commission issued its order approving recovery of the 2010 energy efficiency program costs and a partial performance bonus of approximately $8 million, plus carrying costs, but disallowed a recovery of a performance bonus of $2 million on approximately $10 million in 2008 energy efficiency costs expended pursuant to the terms of a settlement agreement in a prior rate case. CenterPoint Houston began collecting the approved amounts in July 2010. CenterPoint Houston appealed the denial of the full 2008 performance bonus to the 98th district court in Travis County, Texas. In October 2010, the district court upheld the Texas Utility Commission's decision. In February 2011, CenterPoint Houston appealed the district court's judgment to the Texas 3rd Court of Appeals at Austin, Texas, where the case remains pending.

In April 2010, CenterPoint Houston filed an application with the Texas Utility Commission seeking approval of certain estimated 2011 energy efficiency programs, an energy efficiency performance bonus for 2009 programs, and recovery of revenue losses related to the implementation of the 2009 energy efficiency program totaling approximately $14.4 million. The application sought to begin recovery of these costs through a surcharge beginning in January 2011. In November 2010, the Texas Utility Commission issued its order approving recovery of the 2011 energy efficiency program costs and a partial performance bonus of approximately $11 million, but disallowed a recovery of a performance bonus of $2 million on the 2009 energy efficiency costs expended pursuant to the terms of the settlement agreement referenced above. The Texas Utility Commission further concluded that it does not have statutory authority to permit recovery of the approximately $1.4 million in lost revenue associated with 2009 energy efficiency programs. CenterPoint Houston began collecting the approved amounts in January 2011, but has appealed the denial of the full 2009 performance bonus and lost revenue to the 201st district court in Travis County, Texas, where the case remains pending.

Rulemaking Proceedings. In January 2010, the Texas Utility Commission published proposed amendments to its energy efficiency rule. During the statutory comment period, CenterPoint Houston urged, as part of the rule amendments, the adoption of a lost revenue recovery mechanism to keep whole the utilities participating in the required energy efficiency programs. In July 2010, the Texas Utility Commission adopted amendments to its energy efficiency program rules, but concluded it did not have the statutory authority to permit recovery of lost revenue associated with energy efficiency programs. CenterPoint Houston has appealed the rule to the Texas 3rd Court of Appeals at Austin, Texas on the basis that it is invalid as amended because it does not permit lost revenue recovery.

In October 2010, amended rules of the Texas Utility Commission relating to the Transmission Cost Recovery Factor (TCRF) became effective. The amended rules permit a distribution service provider (DSP) such as CenterPoint Houston to defer for future recovery increases in transmission costs that are charged to the DSP by transmission service providers (TSPs) during the interim period before the DSP is authorized to request an adjustment to its TCRF. The TCRF permits a DSP to recover from REPs approved changes in transmission charges from TSPs, but the TCRF can be changed by the DSP only twice per year on application to the Texas Utility Commission. The revised rules permit DSPs to obtain full recovery of the increased transmission charges.

Natural Gas Distribution

In almost all communities in which Gas Operations provides natural gas distribution services, it operates under franchises, certificates or licenses obtained from state and local authorities. The original terms of the franchises, with various expiration dates, typically range from 10 to 30 years, although franchises in Arkansas are perpetual. Gas Operations expects to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of Gas Operations is subject to cost-of-service regulation by the relevant state public utility commissions and, in Texas, by the Railroad Commission of Texas (Railroad Commission) and those municipalities served by Gas Operations that have retained original jurisdiction.

Texas. In March 2008, Gas Operations filed a request to change its rates with the Railroad Commission and the 47 cities in its Texas Coast service territory, an area consisting of approximately 230,000 customers in cities and communities on the outskirts of Houston. In 2008, the Railroad Commission approved the implementation of rates increasing annual revenues by approximately $3.5 million. The approved rates were contested by a coalition of nine cities in an appeal to the 353rd district court in Travis County, Texas. In January 2010, that court reversed the Railroad Commission's order in part and remanded the matter to the Railroad Commission. In its final judgment, the court ruled that the Railroad Commission lacked authority to impose the approved cost of service adjustment mechanism in both those nine cities and in those areas in which the Railroad Commission has original jurisdiction.

The Railroad Commission and Gas Operations have appealed the court's ruling on the cost of service adjustment mechanism to the 3rd Court of Appeals at Austin, Texas. Oral arguments were held in February 2011. The cost of service adjustment was initially effective for three successive years ending in calendar year 2010, but would automatically renew for successive three-year periods unless Gas Operations or the regulatory authority having original jurisdiction gave written notice to discontinue the adjustment mechanism by February 1, 2011. Certain cities that agreed to the initial implementation notified Gas Operations by February 1, 2011 of their desire to discontinue the adjustment mechanism. Gas Operations will continue the cost of service adjustments for the remaining areas.

In July 2009, Gas Operations filed a request to change its rates with the Railroad Commission and the 29 cities in its Houston service territory, consisting of approximately 940,000 customers in and around Houston. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Houston service territory. As finally submitted to the Railroad Commission and the cities, the proposed new rates would have resulted in an overall increase in annual revenue of $20.4 million, excluding carrying costs of approximately $2 million on its gas inventory, and would be subject to an annual cost of service adjustment. In January 2010, Gas Operations withdrew its request for an annual cost of service adjustment mechanism due to the uncertainty caused by the court's ruling in the above-mentioned Texas Coast appeal. In February 2010, the Railroad Commission issued its decision authorizing a revenue increase of $5.1 million annually, reflecting reduced depreciation rates as well as adjustments to pension and other employee benefits, accumulated deferred income taxes and other items. The Railroad Commission also approved a surcharge of $0.9 million per year to recover Hurricane Ike costs over three years. These rates went into effect in March 2010. Gas Operations and other parties are seeking judicial review of the Railroad Commission's decision in the 261st District Court in Travis County, Texas.

In December 2010, Gas Operations filed a request to change its rates with the Railroad Commission and the 66 cities in its South Texas service territory, consisting of approximately 137,000 customers. The request seeks an increase in base revenues of approximately $6.5 million, based on an 11% return on equity and a capital structure of 56% equity and 44% debt. A decision from the Railroad Commission is anticipated in the summer of 2011.

In February 2011, the Railroad Commission approved a rule requiring evaluation of natural gas distribution systems and submission of a plan by August 2011 to address the risks identified. Each operator's risk-based program is to be developed in conjunction with the recently enacted federal regulations regarding integrity management for distribution system operators. The rule allows Gas Operations to record a regulatory asset to account for amounts spent to comply with the rule and to accrue carrying costs. The determination of the reasonableness and necessity of any investment or expense will be determined in the next rate case. We do not anticipate compliance with this rule will cause a material increase in capital expenditures or operating costs.

The Texas legislature periodically reviews the performance of and the need for government agencies such as the Railroad Commission under the Texas Sunset law. In January 2011, the Sunset Commission established by the legislature issued its report on the Railroad Commission for consideration by the Texas legislature during its 2011 session. The recommendations by the Sunset Commission include replacing the three-member elected Railroad Commission with a single elected Commissioner, and moving hearings currently conducted at the Railroad Commission to the State Office of Administrative Hearings. The Sunset Commission also recommended changing the name of the Railroad Commission to the "Texas Oil and Gas Commission." We cannot predict what action, if any, the Texas legislature may take with respect to those recommendations.

Minnesota. In November 2008, Gas Operations filed a request with the Minnesota Public Utilities Commission (MPUC) to increase its rates for utility distribution service by $59.8 million annually. In addition, Gas Operations sought an adjustment mechanism that would annually adjust rates to reflect changes in use per customer. In December 2008, the MPUC accepted the case and approved an interim rate increase of $51.2 million, which became effective on January 2, 2009, subject to refund. In January 2010, the MPUC issued its decision authorizing a revenue increase of $40.8 million per year, with an overall rate of return of 8.09% (10.24% return on equity). The MPUC also authorized Gas Operations to implement a pilot program for residential and small volume commercial customers that is intended to decouple gas revenues from customers' natural gas usage. In July 2010, Gas Operations implemented the revised rates approved by the MPUC and in August 2010 completed the refund to customers of the difference between the amounts finally approved by the MPUC and interim amounts collected. In October 2010, the MPUC approved a request by Gas Operations to implement a rate adjustment to increase its conservation improvement plan (CIP) recovery rate from $9.7 million to $23.2 million annually. In addition, the MPUC approved a $1.4 million incentive based on Gas Operations' 2009 CIP program.

Department of Transportation

In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Act), which reauthorized the programs adopted under the Pipeline Safety Improvement Act of 2002 (2002 Act). These programs included several requirements related to ensuring pipeline safety, and a requirement to assess the integrity of pipeline transmission facilities in areas of high population concentration. Under the 2002 Act, remediation activities are to be performed over a 10-year period. Our pipeline subsidiaries are on schedule to comply with the timeframe mandated for completion of integrity assessment and remediation.

Pursuant to the 2006 Act, the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the Department of Transportation (DOT) issued regulations, effective February 12, 2010, requiring operators of gas distribution pipelines to develop and implement integrity management programs similar to those required for gas transmission pipelines, but tailored to reflect the differences in distribution pipelines. Operators of gas distribution systems must write and implement their integrity management programs by August 2, 2011. CERC's natural gas distribution companies are on schedule to meet this deadline.

Pursuant to the 2002 Act and the 2006 Act, PHMSA has adopted a number of rules concerning, among other things, distinguishing between gathering lines and transmission facilities, requiring certain design and construction features in new and replaced lines to reduce corrosion and requiring pipeline operators to amend existing written operations and maintenance procedures and operator qualification programs. PHMSA has also updated its reporting requirements for natural gas pipelines effective January 1, 2011.

We anticipate that compliance with these regulations and performance of the remediation activities by CERC's interstate and intrastate pipelines and natural gas distribution companies will require increases in both capital expenditures and operating costs. The level of expenditures will depend upon several factors, including age, location and operating pressures of the facilities.

ENVIRONMENTAL MATTERS

Our operations are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of natural gas pipelines and distribution systems, gas gathering and processing systems, and electric transmission and distribution systems, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action to mitigate environmental conditions caused by our operations or attributable to former operations;
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations; and

- impacting the demand for our services by directly or indirectly affecting the use or price of natural gas, or the ability to extract natural gas in areas we serve in our interstate pipelines and field services businesses.

In order to comply with these requirements, we may need to spend substantial amounts and devote other resources from time to time to:

- construct or acquire new equipment;

- acquire permits for facility operations;
- modify or replace existing and proposed equipment; and
- clean up or decommission waste disposal areas, fuel storage and management facilities and other locations and facilities.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial actions and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance.

Based on current regulatory requirements and interpretations, we do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position, results of operations or cash flows. In addition, we believe that our current environmental remediation activities will not materially interrupt or diminish our operational ability. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs. The following is a discussion of all material environmental and safety laws and regulations that relate to our operations. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Global Climate Change

In recent years, there has been increasing public debate regarding the potential impact on global climate change by various “greenhouse gases” (GHGs) such as carbon dioxide, a byproduct of burning fossil fuels, and methane, the principal component of the natural gas that we transport and deliver to customers. Legislation to regulate emissions of GHGs has been introduced in Congress, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industrial sources to meet stringent new standards that would require substantial reductions in carbon emissions. These regulations could be costly and difficult to implement. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues, such as the United Nations Climate Change Conference in Copenhagen in 2009. Also, the U.S. Environmental Protection Agency (EPA) has undertaken new efforts to collect information regarding GHG emissions and their effects. Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA proposed to expand its regulations relating to those emissions and has adopted rules imposing permitting and reporting obligations that we expect to be applicable to certain aspects of our operations. Specifically, the EPA adopted a final rule to address permitting of methane and other GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs. Additionally, the EPA has issued the “Mandatory Reporting of Greenhouse Gases Rule,” which establishes a new comprehensive scheme for reporting GHG emissions. In late 2010, the EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule, and will require facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year to report annual GHG emissions, with the first report due on March 31, 2012. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA.

It is too early to determine whether, or in what form, further regulatory action regarding GHG emissions will be adopted or what specific impacts a new regulatory action might have on us and our subsidiaries. Although it now appears unlikely that new legislation regarding GHGs will be adopted in the near term, action by the EPA to impose new regulations and standards regarding GHG emissions is underway and appears likely to result in new standards and regulatory requirements. As a distributor and transporter of natural gas and consumer of natural gas in its pipeline and gathering businesses, CERC's revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of its operations or would have the effect of reducing the consumption of natural gas. Our electric transmission and distribution business, in contrast to some electric utilities, does not generate electricity and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that burn fossil fuels to generate electricity. Nevertheless, CenterPoint Houston's revenues could be adversely affected to the extent any resulting regulatory action has the effect of reducing consumption of electricity by ultimate consumers within its service territory. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics, would be expected to beneficially affect CERC and its natural gas-related businesses. At this point in time, however, it would be speculative to try to quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on our businesses.

To the extent climate changes occur, our businesses may be adversely impacted, though we believe any such impacts are likely to occur very gradually and hence would be difficult to quantify with specificity. To the extent global climate change results in warmer temperatures in our service territories, financial results from our natural gas distribution businesses could be adversely affected through lower gas sales, and our gas transmission and field services businesses could experience lower revenues. On the other hand, warmer temperatures in our electric service territory may increase our revenues from transmission and distribution through increased demand for electricity for cooling. Another possible climate change is more frequent and more severe weather events, such as hurricanes or tornadoes. Since many of our facilities are located along or near the Gulf Coast, increased or more severe hurricanes or tornadoes can increase our costs to repair damaged facilities and restore service to our customers. When we cannot deliver electricity or natural gas to customers or our customers cannot receive our services, our financial results can be impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs, or if higher rates resulting from our recovery of such costs result in reduced demand for our services, our future financial results may be adversely impacted.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

In 2010, the EPA adopted amendments to its regulations regarding maximum achievable control technology for stationary internal combustion engines (sometimes referred to as the RICE MACT rule) and continues to consider additional amendments. Compressors used by our Pipelines and Field Services segments are affected by these rules. Compliance with the current rules could require capital expenditures of $40 million to $50 million over the next 5 years. The estimated amount does not include costs to comply with new amendments which are expected to be proposed by the EPA for compliance by 2015. We estimate that compliance with these anticipated 2015 RICE MACT amendments as currently envisioned could require capital expenditures of $50 million to $75 million over the next 5 years. We believe, however, that our operations will not be materially adversely affected by such requirements.

Water Discharges

Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into waters of the United States. The unpermitted discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Hazardous Waste

Our operations generate wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act (RCRA), and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste waters produced and other wastes associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes are still regulated under state law and the less stringent non-hazardous waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that would be subject to RCRA or comparable state law requirements.

Liability for Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), also known as “Superfund,” and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released and companies that disposed or arranged for the disposal of hazardous substances at offsite locations such as landfills. Although petroleum, as well as natural gas, is excluded from CERCLA’s definition of a “hazardous substance,” in the course of our ordinary operations we generate wastes that may fall within the definition of a “hazardous substance.” CERCLA authorizes the EPA and, in some cases, third parties to take action in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

Liability for Preexisting Conditions

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, 2010, 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 (PRPs), 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. 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 in 2010. Such refund was completed in August 2010. 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, $5.2 million at December 31, 2010, 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 EPA 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 a 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 CERCLA and applicable state statutes, and is vigorously contesting the suit and its designation as a PRP. We and CERC do not expect the ultimate outcome to have a material adverse impact on the financial condition, results of operations or cash flows of either us or CERC.

Asbestos. Some facilities owned by us contain or have contained asbestos insulation and other asbestos-containing materials. We or our 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 us, but most existing claims relate to facilities previously owned by our subsidiaries. We anticipate that additional claims like those received may be asserted in the future. In 2004, we sold our 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 us and our 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 we have agreed to continue to defend such claims to the extent they are covered by insurance maintained by us, subject to reimbursement of the costs of such defense from NRG Texas LP. Although their ultimate outcome cannot be predicted at this time, we intend to continue vigorously contesting claims that we do not consider to have merit and do not expect, based on our experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on our 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. We 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 us or CERC.

Other Environmental. From time to time we have received notices from regulatory authorities or others regarding our status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, we have 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, we do not expect, based on our experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on our financial condition, results of operations or cash flows.

EMPLOYEES

As of December 31, 2010, we had 8,843 full-time employees. The following table sets forth the number of our employees by business segment:

Business Segment	Number	Number Represented by Unions or Other Collective Bargaining Groups
Electric Transmission & Distribution	2,813	1,270
Natural Gas Distribution	3,586	1,362
Competitive Natural Gas Sales and Services	133	—
Interstate Pipelines	728	—
Field Services	278	—
Other Operations	1,305	—
Total	8,843	2,632

As of December 31, 2010, approximately 30% of our employees are subject to collective bargaining agreements. Collective bargaining agreements with two of our unions, the Gas Workers Union Local No. 340 and the International Brotherhood of Electrical Workers Local 949, that collectively represent approximately 7% of our employees are scheduled to expire in 2011. We have a good relationship with these bargaining units and expect to negotiate new agreements in 2011.

EXECUTIVE OFFICERS
(as of February 15, 2011)

Name	Age	Title
David M. McClanahan	61	President and Chief Executive Officer and Director
Scott E. Rozzell	61	Executive Vice President, General Counsel and Corporate Secretary
Gary L. Whitlock	61	Executive Vice President and Chief Financial Officer
C. Gregory Harper	46	Senior Vice President and Group President, CenterPoint

		Energy Pipelines and Field Services
Thomas R. Standish	61	Senior Vice President and Group President — Regulated Operations

David M. McClanahan has been President and Chief Executive Officer and a director of CenterPoint Energy since September 2002. He served as Vice Chairman of Reliant Energy, Incorporated (Reliant Energy) from October 2000 to September 2002 and as President and Chief Operating Officer of Reliant Energy's Delivery Group from April 1999 to September 2002. He previously served as Chairman of the Board of Directors of ERCOT, Chairman of the Board of the University of St. Thomas in Houston and Chairman of the Board of the American Gas Association. He currently serves on the boards of the Edison Electric Institute and the American Gas Association.

Scott E. Rozzell has served as Executive Vice President, General Counsel and Corporate Secretary of CenterPoint Energy since September 2002. He served as Executive Vice President and General Counsel of the Delivery Group of Reliant Energy from March 2001 to September 2002. Before joining Reliant Energy in 2001, Mr. Rozzell was a senior partner in the law firm of Baker Botts L.L.P. He currently serves on the Board of Directors of the Association of Electric Companies of Texas.

Gary L. Whitlock has served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since September 2002. He served as Executive Vice President and Chief Financial Officer of the Delivery Group of Reliant Energy from July 2001 to September 2002. Mr. Whitlock served as the Vice President, Finance and Chief Financial Officer of Dow AgroSciences, a subsidiary of The Dow Chemical Company, from 1998 to 2001.

C. Gregory Harper has served as Senior Vice President and Group President of CenterPoint Energy Pipelines and Field Services since December 2008. Before joining CenterPoint Energy in 2008, Mr. Harper served as President, Chief Executive Officer and as a Director of Spectra Energy Partners, LP from March 2007 to December

2008. From January 2007 to March 2007, Mr. Harper was Group Vice President of Spectra Energy Corp., and he was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper served as Senior Vice President of Energy Marketing and Management for Duke Energy North America from January 2003 until January 2004 and Vice President of Business Development for Duke Energy Gas Transmission and Vice President of East Tennessee Natural Gas, LLC from March 2002 until January 2003. He currently serves on the Board of Directors of the Interstate Natural Gas Association of America.

Thomas R. Standish has served as Senior Vice President and Group President-Regulated Operations of CenterPoint Energy since August 2005, having previously served as Senior Vice President and Group President and Chief Operating Officer of CenterPoint Houston from June 2004 to August 2005 and as President and Chief Operating Officer of CenterPoint Houston from August 2002 to June 2004. He served as President and Chief Operating Officer for both electricity and natural gas for Reliant Energy's Houston area from 1999 to August 2002.

Item 1A. Risk Factors

We are a holding company that conducts all of our business operations through subsidiaries, primarily CenterPoint Houston and CERC. The following, along with any additional legal proceedings identified or incorporated by reference in Item 3 of this report, summarizes the principal risk factors associated with the businesses conducted by each of these subsidiaries:

Risk Factors Affecting Our Electric Transmission & Distribution Business

Following the exhaustion of all judicial appeals in its true-up proceeding, CenterPoint Houston may lose certain tax benefits and/or may not recover the full amount of its true-up request. Such a result could have an adverse impact on CenterPoint Houston's results of operations, financial condition and cash flows.

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas electric restructuring law. In December 2004, the Texas Utility Commission issued its True-Up Order allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and provided for adjustment of the amount to be recovered to include interest on the balance until recovery, along with the principal portion of additional EMCs returned to customers after August 31, 2004 and certain other adjustments.

CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, that court issued its judgment on the various appeals. In its judgment, the district court:

- reversed the Texas Utility Commission's ruling that had denied CenterPoint Houston recovery of a portion of the capacity auction true-up amounts;
- reversed the Texas Utility Commission's ruling that precluded CenterPoint Houston from recovering the interest component of the EMCs paid to REPs; and
- affirmed the True-Up Order in all other respects.

The district court's decision would have had the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston's initial request.

CenterPoint Houston and other parties appealed the district court's judgment to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court's judgment to the extent it restored the capacity auction true-up amounts;
- reversed the district court's judgment to the extent it upheld the Texas Utility Commission's decision to allow CenterPoint Houston to recover EMCs paid to RRI;

- ordered that the tax normalization issue described below be remanded to the Texas Utility Commission as requested by the Texas Utility Commission; and

- affirmed the district court's judgment in all other respects.

In April 2008, the court of appeals denied all motions for rehearing and reissued substantially the same opinion as it had rendered in December 2007.

In June 2008, CenterPoint Houston petitioned the Texas Supreme Court for review of the court of appeals decision. In its petition, CenterPoint Houston seeks reversal of the parts of the court of appeals decision that (i) denied recovery of EMCs paid to RRI, (ii) denied recovery of the capacity auction true-up amounts allowed by the district court, (iii) affirmed the Texas Utility Commission's rulings that denied recovery of approximately $378 million related to depreciation and (iv) affirmed the Texas Utility Commission's refusal to permit CenterPoint Houston to utilize the partial stock valuation methodology for determining the market value of its former generation assets. Two other petitions for review were filed with the Texas Supreme Court by other parties to the appeal. In those petitions parties contend that (i) the Texas Utility Commission was without authority to fashion the methodology it used for valuing the former generation assets after it had determined that CenterPoint Houston could not use the partial stock valuation method, (ii) in fashioning the method it used for valuing the former generating assets, the Texas Utility Commission deprived parties of their due process rights and an opportunity to be heard, (iii) the net book value of the generating assets should have been adjusted downward due to the impact of a purchase option that had been granted to RRI, (iv) CenterPoint Houston should not have been permitted to recover construction work in progress balances without proving those amounts in the manner required by law and (v) the Texas Utility Commission was without authority to award interest on the capacity auction true up award.

In June 2009, the Texas Supreme Court granted the petitions for review of the court of appeals decision. Oral argument before the court was held in October 2009.

To reflect the impact of the True-Up Order, in 2004 and 2005, we recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in our consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of further review by the Texas Supreme Court, we anticipate that we would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue described below, but could range from $190 million to $440 million (pre-tax) plus interest subsequent to December 31, 2010.

In the True-Up Order, the Texas Utility Commission reduced CenterPoint Houston's stranded cost recovery by approximately $146 million, which was included in the extraordinary loss discussed above, to reflect the present value of certain deferred tax benefits associated with its former electric generation assets. We believe that the Texas Utility Commission based its order on proposed regulations issued by the IRS in March 2003 that would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of ADITC and EDFIT back to customers. However, the IRS subsequently withdrew those proposed normalization regulations and, in March 2008, adopted final regulations that would not permit utilities like CenterPoint Houston to pass the tax benefits back to customers without creating normalization violations. In addition, we received a PLR from the IRS in August 2007, prior to adoption of the final regulations, that confirmed that the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations with respect to the ADITC and EDFIT.

If the Texas Utility Commission's order relating to the ADITC reduction is not reversed or otherwise modified on remand so as to eliminate the normalization violation, the IRS could require us to pay an amount equal to CenterPoint

Houston's unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. Such treatment, if required by the IRS, could have a material adverse impact on our results of operations, financial condition and cash flows in addition to any potential loss resulting from final resolution of the True-Up Order. Following the adoption by the IRS of the final regulations described above, the Texas Utility Commission requested, and the court of appeals ordered, that this issue be remanded to that commission for further consideration. No party has challenged that order by the court of appeals although the Texas Supreme Court has the authority to consider all aspects of the rulings above, not just those challenged specifically by the appellants. We and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate and administrative process. Although the Texas Utility Commission has requested that this issue be remanded to it by the courts and has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation, no prediction can be made as to the ultimate action the Texas Utility Commission may take on this issue on remand.

CenterPoint Houston's receivables are concentrated in a small number of REPs, and any delay or default in payment could adversely affect CenterPoint Houston's cash flows, financial condition and results of operations.

CenterPoint Houston's receivables from the distribution of electricity are collected from REPs that supply the electricity CenterPoint Houston distributes to their customers. As of December 31, 2010, CenterPoint Houston did business with 99 REPs. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for CenterPoint Houston's services or could cause them to delay such payments. CenterPoint Houston depends on these REPs to remit payments on a timely basis. Applicable regulatory provisions require that customers be shifted to a provider of last resort if a REP cannot make timely payments. Applicable Texas Utility Commission regulations significantly limit the extent to which CenterPoint Houston can apply normal commercial terms or otherwise seek credit protection from firms desiring to provide retail electric service in its service territory, and thus remains at risk for payments not made prior to the shift to the provider of last resort. The Texas Utility Commission revised its regulations in 2009 to (i) increase the financial qualifications from REPs that began selling power after January 1, 2009, and (ii) authorize utilities to defer bad debts resulting from defaults by REPs for recovery in a future rate case. A subsidiary of NRG Energy, Inc., NRG Retail, (which acquired the Texas retail business of RRI) and its subsidiaries are together considered the largest REP in CenterPoint Houston's service territory. Approximately 33% of CenterPoint Houston's $138 million in billed receivables from REPs at December 31, 2010 was owed by subsidiaries of NRG Retail and approximately 13% of the $138 million in billed receivables was owed by subsidiaries of TXU Energy Retail. Any delay or default in payment by REPs could adversely affect CenterPoint Houston's cash flows, financial condition and results of operations. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations and claims might be made by creditors involving payments CenterPoint Houston had received from such REP.

Rate regulation of CenterPoint Houston's business may delay or deny CenterPoint Houston's ability to earn a reasonable return and fully recover its costs.

CenterPoint Houston's rates are regulated by certain municipalities and the Texas Utility Commission based on an analysis of its invested capital and its expenses in a test year. Thus, the rates that CenterPoint Houston is allowed to charge may not match its expenses at any given time. The regulatory process by which rates are determined may not always result in rates that will produce full recovery of CenterPoint Houston's costs and enable CenterPoint Houston to earn a reasonable return on its invested capital.

Disruptions at power generation facilities owned by third parties could interrupt CenterPoint Houston's sales of transmission and distribution services.

CenterPoint Houston transmits and distributes to customers of REPs electric power that the REPs obtain from power generation facilities owned by third parties. CenterPoint Houston does not own or operate any power generation facilities. If power generation is disrupted or if power generation capacity is inadequate, CenterPoint Houston's sales of transmission and distribution services may be diminished or interrupted, and its results of operations, financial condition and cash flows could be adversely affected.

CenterPoint Houston’s revenues and results of operations are seasonal.

A significant portion of CenterPoint Houston’s revenues is derived from rates that it collects from each REP based on the amount of electricity it delivers on behalf of such REP. Thus, CenterPoint Houston’s revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues being higher during the warmer months.

Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines and Field Services Businesses

Rate regulation of CERC’s business may delay or deny CERC’s ability to earn a reasonable return and fully recover its costs.

CERC’s rates for Gas Operations are regulated by certain municipalities and state commissions, and for its interstate pipelines by the FERC, based on an analysis of its invested capital and its expenses in a test year. Thus, the rates that CERC is allowed to charge may not match its expenses at any given time. The regulatory process in which rates are determined may not always result in rates that will produce full recovery of CERC’s costs and enable CERC to earn a reasonable return on its invested capital.

CERC’s businesses must compete with alternate energy sources, which could result in CERC marketing less natural gas, and its interstate pipelines and field services businesses must compete directly with others in the transportation, storage, gathering, treating and processing of natural gas, which could lead to lower prices and reduced volumes, either of which could have an adverse impact on CERC’s results of operations, financial condition and cash flows.

CERC competes primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other natural gas distributors and marketers also compete directly with CERC for natural gas sales to end-users. In addition, as a result of federal regulatory changes affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass CERC’s facilities and market, sell and/or transport natural gas directly to commercial and industrial customers. Any reduction in the amount of natural gas marketed, sold or transported by CERC as a result of competition may have an adverse impact on CERC’s results of operations, financial condition and cash flows.

CERC’s two interstate pipelines and its gathering systems compete with other interstate and intrastate pipelines and gathering systems in the transportation and storage of natural gas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service. They also compete indirectly with other forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price, but recently, environmental considerations have grown in importance when consumers consider alternative forms of energy. The actions of CERC’s competitors could lead to lower prices, which may have an adverse impact on CERC’s results of operations, financial condition and cash flows. Additionally, any reduction in the volume of natural gas transported or stored may have an adverse impact on CERC’s results of operations, financial condition and cash flows.

CERC’s natural gas distribution and competitive natural gas sales and services businesses are subject to fluctuations in natural gas prices, which could affect the ability of CERC’s suppliers and customers to meet their obligations or otherwise adversely affect CERC’s liquidity and results of operations.

CERC is subject to risk associated with changes in the price of natural gas. Increases in natural gas prices might affect CERC’s ability to collect balances due from its customers and, for Gas Operations, could create the potential for uncollectible accounts expense to exceed the recoverable levels built into CERC’s tariff rates. In addition, a sustained period of high natural gas prices could (i) apply downward demand pressure on natural gas consumption in the areas in which CERC operates thereby resulting in decreased sales and transportation volumes and revenues and (ii) increase the risk that CERC’s suppliers or customers fail or are unable to meet their obligations. An increase in natural gas prices would also increase CERC’s working capital requirements by increasing the investment that must be made in order to maintain natural gas inventory levels. Additionally, a decrease in natural gas prices could increase the amount of collateral that CERC must provide under its hedging arrangements.

A decline in CERC's credit rating could result in CERC's having to provide collateral under its shipping or hedging arrangements or in order to purchase natural gas.

If CERC's credit rating were to decline, it might be required to post cash collateral under its shipping or hedging arrangements or in order to purchase natural gas. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when CERC was experiencing significant working capital requirements or otherwise lacked liquidity, CERC's results of operations, financial condition and cash flows could be adversely affected.

The revenues and results of operations of CERC's interstate pipelines and field services businesses are subject to fluctuations in the supply and price of natural gas and natural gas liquids and regulatory and other issues impacting our customers' production decisions.

CERC's interstate pipelines and field services businesses largely rely on natural gas sourced in the various supply basins located in the Mid-continent region of the United States. The level of drilling and production activity in these regions is dependent on economic and business factors beyond our control. The primary factor affecting both the level of drilling activity and production volumes is natural gas pricing. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the regions served by our gathering and pipeline transportation systems and our natural gas treating and processing activities. A sustained decline could also lead producers to shut in production from their existing wells. Other factors that impact production decisions include the level of production costs relative to other available production, producers' access to needed capital and the cost of that capital, access to drilling rigs, the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Regulatory changes include the potential for more restrictive rules governing the use of hydraulic fracturing, a process used in the extraction of natural gas from shale reservoir formations, and the use of groundwater in that process. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves or to shut in production from existing reserves. To the extent the availability of this supply is substantially reduced, it could have an adverse effect on CERC's results of operations, financial condition and cash flows.

CERC's revenues from these businesses are also affected by the prices of natural gas and natural gas liquids (NGLs). NGL prices generally fluctuate on a basis that correlates to fluctuations in crude oil prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. The markets and prices for natural gas, NGLs and crude oil depend upon factors beyond our control. These factors include supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors.

CERC's revenues and results of operations are seasonal.

A substantial portion of CERC's revenues is derived from natural gas sales and transportation. Thus, CERC's revenues and results of operations are subject to seasonality, weather conditions and other changes in natural gas usage, with revenues being higher during the winter months.

The actual cost of pipelines and gathering systems under construction, future pipeline, gathering and treating systems and related compression facilities may be significantly higher than CERC had planned.

Subsidiaries of CERC Corp. have been recently involved in significant pipeline and gathering construction projects and, depending on available opportunities, may, from time to time, be involved in additional significant pipeline construction and gathering and treating system projects in the future. The construction of new pipelines, gathering and treating systems and related compression facilities may require the expenditure of significant amounts of capital, which may exceed CERC's estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating or compression facilities is subject to construction cost overruns due to labor costs, costs of equipment and materials such as steel and nickel, labor shortages or delays, weather delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. As a result, there is the risk that the new facilities may not be able to achieve CERC's expected investment return, which could adversely affect CERC's financial condition, results of operations or cash flows.

The states in which CERC provides regulated local gas distribution may, either through legislation or rules, adopt restrictions similar to or broader than those under the Public Utility Holding Company Act of 1935 regarding organization, financing and affiliate transactions that could have significant adverse impacts on CERC's ability to operate.

The Public Utility Holding Company Act of 1935, to which we and our subsidiaries were subject prior to its repeal in the Energy Policy Act of 2005, provided a comprehensive regulatory structure governing the organization, capital structure, intracompany relationships and lines of business that could be pursued by registered holding companies and their member companies. Following repeal of that Act, proposals have been put forth in some of the states in which CERC does business that have sought to expand the state regulatory frameworks to give state regulatory authorities increased jurisdiction and scrutiny over similar aspects of the utilities that operate in their states. Some of these frameworks attempt to regulate financing activities, acquisitions and divestitures, and arrangements between the utilities and their affiliates, and to restrict the level of non-utility business that can be conducted within the holding company structure. Additionally they may impose record keeping, record access, employee training and reporting requirements related to affiliate transactions and reporting in the event of certain downgrading of the utility's bond rating.

These regulatory frameworks could have adverse effects on CERC's ability to conduct its utility operations, to finance its business and to provide cost-effective utility service. In addition, if more than one state adopts restrictions on similar activities, it may be difficult for CERC and us to comply with competing regulatory requirements.

Risk Factors Associated with Our Consolidated Financial Condition

If we are unable to arrange future financings on acceptable terms, our ability to refinance existing indebtedness could be limited.

As of December 31, 2010, we had $9.5 billion of outstanding indebtedness on a consolidated basis, which includes $2.8 billion of non-recourse transition and system restoration bonds. As of December 31, 2010, approximately $1.1 billion principal amount of this debt is required to be paid through 2013. This amount excludes (i) $550 million principal amount of CERC Corp. senior notes that were repaid at their maturity in February 2011 with proceeds from the issuance in January 2011 of $550 million principal amount of CERC Corp. senior notes maturing subsequent to 2013, (ii) $397 million principal amount of CERC Corp. 7.875% senior notes due 2013 that were exchanged in January 2011 for CERC Corp. senior notes maturing subsequent to 2013 and (iii) principal repayments of approximately $920 million on transition and system restoration bonds, for which a dedicated revenue stream exists. Our future financing activities may be significantly affected by, among other things:

- the resolution of the true-up proceedings, including, in particular, the results of appeals to the Texas Supreme Court regarding rulings obtained to date;
- general economic and capital market conditions;
- credit availability from financial institutions and other lenders;
- investor confidence in us and the markets in which we operate;
- maintenance of acceptable credit ratings;
- market expectations regarding our future earnings and cash flows;

- market perceptions of our ability to access capital markets on reasonable terms;

- our exposure to GenOn in connection with its indemnification obligations arising in connection with its separation from us;

- incremental collateral that may be required due to regulation of derivatives; and
- provisions of relevant tax and securities laws.

As of December 31, 2010, CenterPoint Houston had approximately $2.5 billion aggregate principal amount of general mortgage bonds outstanding under the General Mortgage, (a) including $290 million held in trust to secure pollution control bonds that are not reflected on our consolidated financial statements because we are both the obligor on the bonds and the owner of the bonds, (b) an additional approximately $237 million held in trust to secure pollution control bonds for which we are obligated and (c) approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had approximately $253 million aggregate principal amount of first mortgage bonds outstanding under the Mortgage, including approximately $151 million held in trust to secure certain pollution control bonds for which we are obligated. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $2.3 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2010. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

Our current credit ratings are discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Sources and Uses of Cash — Impact on Liquidity of a Downgrade in Credit Ratings" in Item 7 of Part II of this report. These credit ratings may not remain in effect for any given period of time and one or more of these ratings may be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to access capital on acceptable terms.

As a holding company with no operations of our own, we will depend on distributions from our subsidiaries to meet our payment obligations, and provisions of applicable law or contractual restrictions could limit the amount of those distributions.

We derive all our operating income from, and hold all our assets through, our subsidiaries. As a result, we will depend on distributions from our subsidiaries in order to meet our payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide us with funds for our payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit our subsidiaries' ability to make payments or other distributions to us, and our subsidiaries could agree to contractual restrictions on their ability to make distributions.

Our right to receive any assets of any subsidiary, and therefore the right of our creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if we were a creditor of any subsidiary, our rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by us.

The use of derivative contracts by us and our subsidiaries in the normal course of business could result in financial losses that could negatively impact our results of operations and those of our subsidiaries.

We and our subsidiaries use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity, weather and financial market risks. We and our subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or should a counterparty fail to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Risks Common to Our Businesses and Other Risks

We are subject to operational and financial risks and liabilities arising from environmental laws and regulations.

Our operations are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of natural gas pipelines and distribution systems, gas gathering and processing systems, and electric transmission and distribution systems, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;
- requiring remedial action to mitigate environmental conditions caused by our operations, or attributable to former operations;
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations; and
- impacting the demand for our services by directly or indirectly affecting the use or price of natural gas, or the ability to extract natural gas in areas we serve in our interstate pipelines and field services businesses.

In order to comply with these requirements, we may need to spend substantial amounts and devote other resources from time to time to:

- construct or acquire new equipment;
- acquire permits for facility operations;
- modify or replace existing and proposed equipment; and
- clean up or decommission waste disposal areas, fuel storage and management facilities and other locations and facilities.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial actions, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

Our insurance coverage may not be sufficient. Insufficient insurance coverage and increased insurance costs could adversely impact our results of operations, financial condition and cash flows.

We currently have general liability and property insurance in place to cover certain of our facilities in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles and do not include business interruption coverage. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of our facilities may not be sufficient to restore the loss or damage without negative impact on our results of operations, financial condition and cash flows.

In common with other companies in its line of business that serve coastal regions, CenterPoint Houston does not have insurance covering its transmission and distribution system, other than substations, because CenterPoint Houston believes it to be cost prohibitive. In the future, CenterPoint Houston may not be able to recover the costs incurred in restoring its transmission and distribution properties following hurricanes or other natural disasters through issuance of storm restoration bonds or a change in its regulated rates or otherwise, or any such recovery may not be timely granted. Therefore, CenterPoint Houston may not be able to restore any loss of, or damage to, any of its transmission and distribution properties without negative impact on its results of operations, financial condition and cash flows.

We, CenterPoint Houston and CERC could incur liabilities associated with businesses and assets that we have transferred to others.

Under some circumstances, we, CenterPoint Houston and CERC could incur liabilities associated with assets and businesses we, CenterPoint Houston and CERC no longer own. These assets and businesses were previously owned by Reliant Energy, Incorporated (Reliant Energy), a predecessor of CenterPoint Houston, directly or through subsidiaries and include:

- merchant energy, energy trading and REP businesses transferred to RRI or its subsidiaries in connection with the organization and capitalization of RRI prior to its initial public offering in 2001; and

- Texas electric generating facilities transferred to Texas Genco Holdings, Inc. (Texas Genco) in 2004 and early 2005.

In connection with the organization and capitalization of RRI, that company and its subsidiaries assumed liabilities associated with various assets and businesses Reliant Energy transferred to them. RRI also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, us and our subsidiaries, including CenterPoint Houston and CERC, with respect to liabilities associated with the transferred assets and businesses. These indemnity provisions were intended to place sole financial responsibility on RRI and its subsidiaries for all liabilities associated with the current and historical businesses and operations of RRI, regardless of the time those liabilities arose. If GenOn were unable to satisfy a liability that has been so assumed in circumstances in which Reliant Energy and its subsidiaries were not released from the liability in connection with the transfer, we, CenterPoint Houston or CERC could be responsible for satisfying the liability.

In May 2009, RRI sold its Texas retail business to NRG Retail, a subsidiary of NRG Energy, Inc. In December 2010, Mirant Corporation merged with and became a wholly owned subsidiary of RRI (then known as RRI Energy, Inc.) and RRI changed its name from RRI Energy, Inc. to GenOn Energy, Inc. Neither the sale of the retail business nor the merger with Mirant Corporation alters GenOn’s contractual obligations to indemnify us and our subsidiaries, including CenterPoint Houston, for certain liabilities, including their indemnification obligations regarding certain litigation, nor does it affect the terms of existing guaranty arrangements for certain GenOn gas transportation contracts.

Prior to the distribution of our ownership in RRI to our 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 (now GenOn) 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 based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $112 million as of December 31, 2010. Market conditions in the fourth quarter of 2010 required posting of security under the agreement, and GenOn posted approximately $7 million in collateral in December 2010. If GenOn 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.

GenOn's unsecured debt ratings are currently below investment grade. If GenOn were unable to meet its obligations, it would need to consider, among various options, restructuring under the bankruptcy laws, in which event GenOn might not honor its indemnification obligations and claims by GenOn's creditors might be made against us as its former owner.

Reliant Energy and RRI (GenOn's predecessors) are named as defendants in a number of lawsuits arising out of sales of natural gas in California and other markets. Although these matters relate to the business and operations of GenOn, claims against Reliant Energy have been made on grounds that include liability of Reliant Energy as a controlling shareholder of GenOn's predecessor. We, CenterPoint Houston or CERC could incur liability if claims in one or more of these lawsuits were successfully asserted against us, CenterPoint Houston or CERC and indemnification from GenOn were determined to be unavailable or if GenOn were unable to satisfy indemnification obligations owed with respect to those claims.

In connection with the organization and capitalization of Texas Genco, Reliant Energy and Texas Genco entered into a separation agreement in which Texas Genco assumed liabilities associated with the electric generation assets Reliant Energy transferred to it. Texas Genco also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, us and our subsidiaries, including CenterPoint Houston, with respect to liabilities associated with the transferred assets and businesses. In many cases the liabilities assumed were obligations of CenterPoint Houston, and CenterPoint Houston was not released by third parties from these liabilities. The indemnity provisions were intended generally to place sole financial responsibility on Texas Genco and its subsidiaries for all liabilities associated with the current and historical businesses and operations of Texas Genco, regardless of the time those liabilities arose. If Texas Genco were unable to satisfy a liability that had been so assumed or indemnified against, and provided we or Reliant Energy had not been released from the liability in connection with the transfer, CenterPoint Houston could be responsible for satisfying the liability.

In connection with our sale of Texas Genco to a third party, the separation agreement was amended to provide that Texas Genco would no longer be liable for, and we would assume and agree to indemnify Texas Genco against, liabilities that Texas Genco originally assumed in connection with its organization to the extent, and only to the extent, that such liabilities are covered by certain insurance policies held by us. Texas Genco and its related businesses now operate as subsidiaries of NRG Energy, Inc.

We or our 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 us, but most existing claims relate to facilities previously owned by our subsidiaries but currently owned by NRG Texas LP. We anticipate that additional claims like those received may be asserted in the future. Under the terms of the arrangements regarding separation of the generating business from us 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 we have agreed to continue to defend such claims to the extent they are covered by insurance maintained by us, subject to reimbursement of the costs of such defense by NRG Texas LP.

The unsettled conditions in the global financial system may have impacts on our business, liquidity and financial condition that we currently cannot predict.

The continued unsettled conditions in the global financial system may have an impact on our business, liquidity and financial condition. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to access those markets, which could have an impact on our liquidity and flexibility to react to changing economic and business conditions. In addition, the cost of debt financing and the proceeds of equity financing may be materially adversely impacted by these market conditions. Defaults of lenders in our credit facilities, should they further occur, could adversely affect our liquidity. Capital market turmoil was reflected in significant reductions in equity market valuations in 2008, which significantly reduced the value of assets of our pension plan. These reductions increased non-cash pension expense in 2009 and may impact liquidity if contributions are made to offset reduced asset values.

In addition to the credit and financial market issues, national and local recessionary conditions may impact our business in a variety of ways. These include, among other things, reduced customer usage, increased customer default rates and wide swings in commodity prices.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for our services.

Legislation to regulate emissions of GHGs has been introduced in Congress, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues, such as the United Nations Climate Change Conference in Copenhagen in 2009. Also, the EPA has undertaken new efforts to collect information regarding GHG emissions and their effects. Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA proposed to expand its regulations relating to those emissions and has adopted rules imposing permitting and reporting obligations that we expect to be applicable to certain of our operations. The results of the permitting and reporting requirements could lead to further regulation of these GHGs by the EPA It is too early to determine whether, or in what form, further regulatory action regarding GHG emissions will be adopted or what specific impacts a new regulatory action might have on us and our subsidiaries. Action by the EPA to impose new regulations and standards regarding GHG emissions is underway and appears likely to result in new standards and regulatory requirements. As a distributor and transporter of natural gas and consumer of natural gas in its pipeline and gathering businesses, CERC's revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of its operations or would have the effect of reducing the consumption of natural gas. Our electric transmission and distribution business, in contrast to some electric utilities, does not generate electricity and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that burn fossil fuels to generate electricity. Nevertheless, CenterPoint Houston's revenues could be adversely affected to the extent any resulting regulatory action has the effect of reducing consumption of electricity by ultimate consumers within its service territory. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services.

Climate changes could result in more frequent severe weather events which could affect the results of operations of our businesses.

To the extent climate changes occur, our businesses may be adversely impacted, though we believe any such impacts are likely to occur very gradually and hence would be difficult to quantify with specificity. To the extent global climate change results in warmer temperatures in our service territories, financial results from our natural gas distribution businesses could be adversely affected through lower gas sales, and our gas transmission and field services businesses could experience lower revenues. Another possible climate change is more frequent and more severe weather events, such as hurricanes or tornadoes. Since many of our facilities are located along or near the Gulf Coast, increased or more severe hurricanes or tornadoes can increase our costs to repair damaged facilities and restore service to our customers. When we cannot deliver electricity or natural gas to customers or our customers cannot receive our services, our financial results can be impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs, or if higher rates resulting from our recovery of such costs result in reduced demand for our services, our future financial results may be adversely impacted.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Character of Ownership

We own or lease our principal properties in fee, including our corporate office space and various real property. Most of our electric lines and gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

Electric Transmission & Distribution

For information regarding the properties of our Electric Transmission & Distribution business segment, please read "Business — Our Business — Electric Transmission & Distribution — Properties" in Item 1 of this report, which information incorporated herein by reference.

Natural Gas Distribution

For information regarding the properties of our Natural Gas Distribution business segment, please read "Business — Our Business — Natural Gas Distribution — Assets" in Item 1 of this report, which information is incorporated herein by reference.

Competitive Natural Gas Sales and Services

For information regarding the properties of our Competitive Natural Gas Sales and Services business segment, please read "Business — Our Business — Competitive Natural Gas Sales and Services — Assets" in Item 1 of this report, whic information is incorporated herein by reference.

Interstate Pipelines

For information regarding the properties of our Interstate Pipelines business segment, please read "Business — Our Business — Interstate Pipelines — Assets" in Item 1 of this report, which information is incorporated herein by reference.

Field Services

For information regarding the properties of our Field Services business segment, please read "Business — Our Business — Field Services — Assets" in Item 1 of this report, which information is incorporated herein by reference.

Other Operations

For information regarding the properties of our Other Operations business segment, please read "Business — Our Business — Other Operations" in Item 1 of this report, which information is incorporated herein by reference.

Item 3. Legal Proceedings

For a discussion of material legal and regulatory proceedings affecting us, please read "Business — Regulation" and "Business — Environmental Matters" in Item 1 of this report and Notes 5 and 13(f) to our consolidated financial statements, which information is incorporated herein by reference.

Item 4. Removed and Reserved

PART II

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

As of February 15, 2011, our common stock was held of record by approximately 43,347 shareholders. Our common stock is listed on the New York and Chicago Stock Exchanges and is traded under the symbol "CNP."

The following table sets forth the high and low closing prices of the common stock of CenterPoint Energy on the New York Stock Exchange composite tape during the periods indicated, as reported by Bloomberg, and the cash dividends declared in these periods.

	Market Price		Dividend Declared Per Share
	High	Low	
2009			
First Quarter			$ 0.19
February 6	$ 14.39		
March 6		$ 8.88	
Second Quarter			$ 0.19
May 27		$ 9.77	
June 29	$ 11.24		
Third Quarter			$ 0.19
July 9		$ 10.78	
August 26	$ 12.83		
Fourth Quarter			$ 0.19
October 2		$ 12.22	
December 28	$ 14.81		
2010			
First Quarter			$ 0.195
January 20	$ 14.86		
February 26		$ 13.38	
Second Quarter			$ 0.195
April 6	$ 14.74		
June 9		$ 12.90	
Third Quarter			$ 0.195

July 2		$ 13.03	
September 28	$ 15.84		
Fourth Quarter			$ 0.195
November 4	$ 16.92		
November 29		$ 15.60	

The closing market price of our common stock on December 31, 2010 was $15.72 per share.

The amount of future cash dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable contractual restrictions and other factors that our board of directors considers relevant and will be declared at the discretion of the board of directors.

On January 20, 2011, we announced a regular quarterly cash dividend of $0.1975 per share, payable on March 10, 2011 to shareholders of record on February 16, 2011.

Repurchases of Equity Securities

During the quarter ended December 31, 2010, none of our equity securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our "affiliated purchasers," as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934.

Item 6. Selected Financial Data

The following table presents selected financial data with respect to our consolidated financial condition and consolidated results of operations and should be read in conjunction with our consolidated financial statements and the related notes in Item 8 of this report.

	Year Ended December 31, 2006(1)	2007(1)	2008(1)	2009	2010
	(in millions, except per share amounts)				
Revenues	$ 9,319	$ 9,623	$ 11,322	$ 8,281	$ 8,785
Net income	$ 427	$ 395	$ 446	$ 372	$ 442
Basic earnings per common share	$ 1.37	$ 1.23	$ 1.32	$ 1.02	$ 1.08
Diluted earnings per common share	$ 1.31	$ 1.15	$ 1.30	$ 1.01	$ 1.07
Cash dividends declared per common share	$ 0.60	$ 0.68	$ 0.73	$ 0.76	$ 0.78
Dividend payout ratio	44 %	55 %	55 %	75 %	72 %
Return on average common equity	29.8 %	23.4 %	23.3 %	16.0 %	15.1 %
Ratio of earnings to fixed charges	1.74	1.83	2.05	1.82	2.08
At year-end:					
Book value per common share	$ 4.98	$ 5.61	$ 5.84	$ 6.74	$ 7.53
Market price per common share	16.58	17.13	12.62	14.51	15.72
Market price as a percent of book value	333 %	305 %	216 %	215 %	209 %
Total assets	$ 17,633	$ 17,872	$ 19,676	$ 19,773	$ 20,111
Short-term borrowings	187	232	153	55	53
Transition and system restoration bonds, including current maturities	2,407	2,260	2,589	3,046	2,805
Other long-term debt, including current maturities	6,586	7,417	7,925	6,976	6,624
Capitalization:					
Common stock equity	15 %	16 %	16 %	21 %	25 %
Long-term debt, including current maturities	85 %	84 %	84 %	79 %	75 %
Capitalization, excluding transition and system restoration bonds:					
Common stock equity	19 %	20 %	20 %	27 %	33 %
Long-term debt, excluding transition and system restoration bonds, including current maturities	81 %	80 %	80 %	73 %	67 %
Capital expenditures	$ 1,121	$ 1,011	$ 1,053	$ 1,148	$ 1,462

(1) Net income has been retrospectively adjusted by $5 million, $4 million and $1 million for the years ended 2006, 2007 and 2008, respectively, to reflect the adoption of new accounting guidance as of January 1, 2009 for convertible debt instruments that may be settled in cash upon conversion.

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

The following discussion and analysis should be read in combination with our consolidated financial statements included in Item 8 herein.

OVERVIEW

Background

We are a public utility holding company whose indirect wholly owned subsidiaries include:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in a 5,000-square mile area of the Texas Gulf Coast that includes the city of Houston; and

- CenterPoint Energy Resources Corp. (CERC Corp. and, together with its subsidiaries, CERC), which owns and operates natural gas distribution systems in six states. Subsidiaries of CERC Corp. own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of CERC Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

Business Segments

In this Management's Discussion, we discuss our results from continuing operations on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and certain critical accounting policies. We are first and foremost an energy delivery company and it is our intention to remain focused on this segment of the energy business. The results of our business operations are significantly impacted by weather, customer growth, economic conditions, cost management, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to which we are subject. Our electric transmission and distribution services are subject to rate regulation and are reported in the Electric Transmission & Distribution business segment, as are impacts of generation-related stranded costs and other true-up balances recoverable by the regulated electric utility. Our natural gas distribution services are also subject to rate regulation and are reported in the Natural Gas Distribution business segment. A summary of our reportable business segments as of December 31, 2010 is set forth below:

Electric Transmission & Distribution

Our electric transmission and distribution operations provide electric transmission and distribution services to retail electric providers (REPs) serving approximately 2.1 million metered customers in a 5,000-square-mile area of the Texas Gulf Coast that has a population of approximately 5.9 million people and includes the city of Houston.

On behalf of REPs, CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers in locations throughout CenterPoint Houston's certificated service territory. The Electric Reliability Council of Texas, Inc. (ERCOT) serves as the regional reliability coordinating council for member electric power systems in Texas. ERCOT membership is open to consumer groups, investor and municipally-owned electric utilities, rural electric cooperatives, independent generators, power marketers, river authorities and REPs. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation's largest power markets. Transmission and distribution services are provided under tariffs approved by the Public Utility Commission of Texas (Texas Utility Commission).

Natural Gas Distribution

CERC owns and operates our regulated natural gas distribution business (Gas Operations), which engages in intrastate natural gas sales to, and natural gas transportation for, approximately 3.3 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas.

Competitive Natural Gas Sales and Services

CERC's operations also include non-rate regulated retail and wholesale natural gas sales to, and transportation services for, commercial and industrial customers in 23 states in the central and eastern regions of the United States.

Interstate Pipelines

CERC's interstate pipelines business owns and operates approximately 8,000 miles of natural gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. It also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.3 billion cubic feet (Bcf) and a combined working gas capacity of approximately 59 Bcf. It also owns a 50% interest in Southeast Supply Header, LLC (SESH). SESH owns a 1.0 Bcf per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama. Most storage operations are in north Louisiana and Oklahoma.

Field Services

CERC's field services business owns and operates approximately 3,800 miles of gathering pipelines and processing plants that collect, treat and process natural gas primarily from three regions located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas. It also owns a 50% general partnership interest in Waskom Gas Processing Company (Waskom). Waskom owns a natural gas processing plant and natural gas gathering assets located in East Texas. The plant is capable of processing approximately 285 million cubic feet (MMcf) per day of natural gas. The gathering assets are capable of gathering approximately 75 MMcf per day of natural gas.

Other Operations

Our other operations business segment includes office buildings and other real estate used in our business operations and other corporate operations which support all of our business operations.

EXECUTIVE SUMMARY

Factors Influencing Our Business

We are an energy delivery company. The majority of our revenues are generated from the gathering, processing, transportation and sale of natural gas and the transportation and delivery of electricity by our subsidiaries. We do not own or operate electric generating facilities or make retail sales to end-use electric customers. To assess our financial performance, our management primarily monitors operating income and cash flows from our five business segments. Within these broader financial measures, we monitor margins, operation and maintenance expense, interest expense, capital spending and working capital requirements. In addition to these financial measures we also monitor a number of variables that management considers important to the operation of our business segments, including the number of customers, throughput, use per customer, commodity prices and heating and cooling degree days. We also monitor system reliability, safety factors and customer satisfaction to gauge our performance.

To the extent adverse economic conditions affect our suppliers and customers, results from our energy delivery businesses may suffer. Reduced demand and lower energy prices could lead to financial pressure on some of our customers who operate within the energy industry. Also, adverse economic conditions, coupled with concerns for protecting the environment, may cause consumers to use less energy or avoid expansions of their facilities, resulting in less demand for our services.

Performance of our Electric Transmission & Distribution and Natural Gas Distribution business segments is significantly influenced by the number of customers and energy usage per customer. Weather conditions can have a significant impact on energy usage, and we compare our results on a weather adjusted basis. During 2009 and continuing into 2010, we saw evidence that customers are seeking to reduce their energy consumption, particularly during periods of high energy prices or in times of economic distress. That conservation can have adverse effects on our results. In many of our service areas, particularly in the Houston area and in Minnesota, we have benefited from customer growth that tends to mitigate the effects of reduced consumption. We anticipate that this growth will continue despite recent economic downturns, though that growth may be lower than we have recently experienced in these areas. In addition, the profitability of these businesses is influenced significantly by the regulatory treatment we receive from the various state and local regulators who set our electric and gas distribution rates. In recent rate filings, we have sought rate mechanisms that help to decouple our results from the impacts of weather and conservation, but such rate mechanisms have not yet been approved in all jurisdictions. We plan to continue to pursue such decoupling mechanisms in our rate filings.

Our Field Services and Interstate Pipelines business segments are currently benefiting from their proximity to new natural gas producing regions in Texas, Arkansas, Oklahoma and Louisiana. Our Interstate Pipelines business segment benefited from new projects placed into service in 2009 on our Carthage to Perryville line, including a backhaul agreement due to expire in 2011. In our Field Services business segment, strong shale drilling activity has helped offset declines in traditional drilling activity. In monitoring performance of the segments, we focus on throughput of the pipelines and gathering systems, and in the case of Field Services, on well-connects.

Our Competitive Natural Gas Sales and Services business segment contracts with customers for transportation, storage and sales of natural gas on an unregulated basis. Its operations serve customers in the central and eastern regions of the United States. The segment benefits from favorable price differentials, either on a geographic basis or on a seasonal basis. While it utilizes financial derivatives to hedge its exposure to price movements, it does not engage in speculative or proprietary trading and maintains a low value at risk level, or VaR, to avoid significant financial exposures. Lower commodity prices and low price differentials during 2009 and 2010 adversely affected results for this business segment.

The nature of our businesses requires significant amounts of capital investment, and we rely on internally generated cash, borrowings under our credit facilities, proceeds from commercial paper and issuances of debt and equity in the capital markets to satisfy these capital needs. We strive to maintain investment grade ratings for our securities in order to access the capital markets on terms we consider reasonable. Our goal is to improve our credit ratings over time. A reduction in our ratings generally would increase our borrowing costs for new issuances of debt, as well as borrowing costs under our existing revolving credit facilities, and may prevent us from accessing the commercial paper markets. Disruptions in the financial markets, such as occurred in the last half of 2008 and continued during 2009, can also affect the availability of new capital on terms we consider attractive. In those circumstances, companies like us may not be able to obtain certain types of external financing or may be required to accept terms less favorable than they would otherwise accept. For that reason, we seek to maintain adequate liquidity for our businesses through existing credit facilities and prudent refinancing of existing debt. For example, we have amended the financial covenant in our revolving credit facility to enhance our ability to incur additional debt if needed to finance restoration costs following major storms.

As it did with many businesses, the sharp decline in stock market values during the latter part of 2008 had a significant adverse impact on the value of our pension plan assets. While that impact did not require us to make additional contributions to the pension plan, it significantly increased the pension expense we recognized during 2009. We expect to make a minimum required contribution to our pension plan of $35 million in 2011 and may need to make larger contributions in subsequent years. Consistent with the regulatory treatment of such costs, we can defer the amount of pension expense that differs from the level of pension expense included in our base rates for our Electric Transmission & Distribution business segment.

Significant Events

Long-Term Gas Gathering and Treating Agreements

Magnolia Gathering System. In September 2009, CenterPoint Energy Field Services, LLC (CEFS) 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. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Magnolia Gathering System) from Encana and Shell in northwest Louisiana. Each of the agreements includes acreage dedication and volume commitments for which CEFS has exclusive rights to gather Shell's and Encana's natural gas production.

During the year ended December 31, 2010, CEFS substantially completed the construction and initial expansion of the Magnolia Gathering System in order to permit the system to gather and treat up to 700 MMcf per day of natural gas, with only well connects remaining. As of December 31, 2010, CEFS had spent approximately $310 million on the original project scope, including the purchase of the original facilities and is in the second year of the 10-year 700 MMcf per day volume commitment made by Shell and Encana.

Pursuant to an expansion election made by Encana and Shell in March 2010, CEFS expanded the Magnolia Gathering System to increase its gathering and treating capacity by an additional 200 MMcf per day, increasing the aggregate capacity of the system to 900 MMcf per day. As of December 31, 2010, CEFS had spent approximately $47 million on the expansion. The expansion was completed and placed into service in February 2011 at a total cost of approximately $52 million. The 200 MMcf per day incremental 10-year volume commitment made by Shell and Encana began contemporaneously with the completion of the expansion.

Under the long-term agreements, Encana or Shell may elect to require CEFS to expand the capacity of the Magnolia Gathering System by up to an additional 800 MMcf per day, bringing the total system capacity to 1.7 Bcf per day. CEFS estimates that the cost to expand the capacity of the Magnolia Gathering System by an additional 800 MMcf per day would be as much as $240 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Olympia Gathering System. In April 2010, CEFS entered into additional long-term agreements with Encana and Shell to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Olympia Gathering System) from Encana and Shell in northwest Louisiana.

Under the terms of the agreements, CEFS is expanding the Olympia Gathering System in order to permit the system to gather and treat up to 600 MMcf per day of natural gas. As of December 31, 2010, CEFS had spent approximately $340 million on the 600 MMcf per day project, including the purchase of the original facilities, and expects to incur up to an additional $85 million to complete this expansion. CEFS expects the full 600 MMcf per day of capacity to be in service in the first quarter of 2011. CEFS is in the first year of the 10-year 600 MMcf per day volume commitment made by Shell and Encana.

Under the long-term agreements, Encana and Shell may elect to require CEFS to expand the capacity of the Olympia Gathering System by up to an additional 520 MMcf per day, bringing the total system capacity to 1.1 Bcf per day. CEFS estimates that the cost to expand the capacity of the Olympia Gathering System by an additional 520 MMcf per day would be as much as $200 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Advanced Metering System and Distribution Grid Automation (Intelligent Grid)

In October 2009, the U.S. Department of Energy (DOE) notified CenterPoint Houston that it had been selected for a $200 million grant for its advanced metering system (AMS) and intelligent grid (IG) projects. In March 2010, CenterPoint Houston and the DOE completed negotiations and finalized the agreement. Under the terms of the agreement, the DOE has agreed to reimburse CenterPoint Houston for 50% of its eligible costs until the total amount of the grant has been paid. Through December 31, 2010, CenterPoint Houston has requested $100 million of grant funding from the DOE, of which $90 million had been received. CenterPoint Houston estimates that capital expenditures of approximately $645 million for the installation of the advanced meters and corresponding communication and data management systems will be incurred over the deployment period. CenterPoint Houston is using $150 million of the grant funding to accelerate completion of its current deployment of advanced meters to 2012, instead of 2014 as originally scheduled. CenterPoint Houston will use the other $50 million from the grant to begin deployment of an IG in a portion of its service territory over the next three years. It is expected that the portion of the IG project subject to funding by the DOE will cost approximately $115 million. CenterPoint Houston believes the IG has the potential to provide an improvement in grid planning, operations, maintenance and customer service for its distribution system.

In March 2010, the Internal Revenue Service (IRS) announced through the issuance of Revenue Procedure 2010-20 that it was providing a safe harbor to corporations that receive a Smart Grid Investment Grant. The IRS stated that it would not challenge a corporation's treatment of the grant as a non-taxable non-shareholder contribution to capital as long as the corporation properly reduced the tax basis of specified property acquired.

CenterPoint Houston Rate Case

As required under the final order in its 2006 rate proceeding, in June 2010 CenterPoint Houston filed an application to change rates with the Texas Utility Commission and the cities in its service area, including cost data and other information supporting an annual increase of $106 million for delivery charges to the REPs that sell electricity to end-use customers in CenterPoint Houston's service territory that was offset by a reduction of other utility revenues, resulting in a $92 million requested annual revenue increase. The rate filing package also supported an annual increase of $18 million for wholesale transmission customers.

In the filing, CenterPoint Houston also requested reconciliation of its AMS costs incurred as of March 31, 2010, and revision of the estimated costs to complete the AMS project in order to reflect $150 million in funds from the $200 million DOE stimulus grant awarded to CenterPoint Houston and updated cost information. The reconciliation plan also requested that the duration of the residential AMS surcharge be shortened by six years from the original 12-year plan.

In its rate filing, CenterPoint Houston sought a return on equity of 11.25% and proposed that rates be based on a capital structure of 50% equity and 50% long-term debt.

Hearings concerning the rate filing concluded in October 2010, and a Proposal for Decision was issued by the presiding Administrative Law Judges. On February 3, 2011 the Texas Utility Commission voted on the various contested issues presented by the rate filing. The Texas Utility Commission has not yet issued a formal order implementing its decisions, and the order, once issued, will be subject to revision based on motions for rehearing by the parties to the proceeding and could be appealed to the Texas courts.

Based on the public deliberations and votes by the Commissioners, CenterPoint Houston anticipates that the order of the Texas Utility Commission will provide for a base rate increase for CenterPoint Houston of approximately $14.7 million per year for delivery charges to the REPs and a decrease to charges to wholesale transmission customers of $12.3 million per year. Further, the order is expected to provide a mechanism to track amounts for uncertain tax positions and provide for ultimate recovery of those costs.

The order is expected to be based on an authorized return on equity for CenterPoint Houston of 10%, a cost of debt of –6.74–%, a capital structure comprised of 55% debt and 45% common equity, and an overall rate of return of 8.21%. The decision also will implement CenterPoint Houston's request to reconcile costs incurred for the AMS project and to shorten the period for collecting the AMS surcharge from twelve to six years for residential customers in order to reflect the funds received from the DOE.

Based on CenterPoint Houston's understanding of the Texas Utility Commission's votes, CenterPoint Houston anticipates that annual operating income will be reduced by approximately $30 million from 2010 levels as a result of the Texas Utility Commission's decision. CenterPoint Houston expects that revised rates based on the Texas Utility Commission's decision will be implemented during the second quarter of 2011.

Debt Financing Transactions

In January 2010, we purchased $290 million principal amount of pollution control bonds issued on our behalf at 101% of their principal amount plus accrued interest pursuant to the mandatory tender provisions of the bonds. Prior to the purchase, the pollution control bonds had a fixed rate of interest of 5.125%. The purchase reduced temporary investments and leverage while providing us with the flexibility to finance future capital needs in the tax-exempt market through a remarketing of these bonds.

In January 2010, CERC Corp. redeemed $45 million of its outstanding 6% convertible subordinated debentures due 2012 at 100% of the principal amount plus accrued and unpaid interest to the redemption date.

In September 2010, we repaid $200 million principal amount of 7.25% senior notes on their maturity date.

In January 2011, CERC Corp. issued $250 million aggregate principal amount of senior notes due 2021 with an interest rate of 4.50% and $300 million aggregate principal amount of senior notes due 2041 with an interest rate of 5.85%. The proceeds from the issuance of the notes were used for the repayment of $550 million of CERC Corp.'s 7.75% senior notes at their maturity in February 2011.

Also in January 2011, CERC Corp. issued an additional $343 million aggregate principal amount of 4.50% senior notes due 2021 and provided cash consideration of $114 million in exchange for $397 million aggregate principal amount of its 7.875% senior notes due 2013. The premium of $58 million paid on exchanged notes has been deferred and will be amortized to interest expense over the life of the 4.50% senior notes due 2021.

Equity Financing Transactions

During the year ended December 31, 2010, we received net proceeds of approximately $315 million from the issuance of 25.3 million common shares in an underwritten public offering, proceeds of approximately $79 million from the sale of approximately 5.4 million common shares to our defined contribution plan and proceeds of approximately $15 million from the sale of approximately 1.0 million common shares to participants in our enhanced dividend reinvestment plan. In January 2011, we suspended the issuance of common shares to our defined contribution plan and our enhanced dividend reinvestment plan. Common shares for the two plans are now being purchased on the open market.

Financial Reform Legislation

On July 21, 2010 the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank), which makes substantial changes to regulatory oversight regarding banks and financial institutions. Many provisions of Dodd-Frank will also affect non-financial businesses such as those conducted by us and our subsidiaries. It is not possible at this time to predict the ultimate impacts this legislation may have on us and our subsidiaries since most of the provisions in the law will require extensive rulemaking by various regulatory agencies and authorities, including, among others, the Securities and Exchange Commission (SEC), the Commodities Futures Trading Commission (CFTC) and the New York Stock Exchange (NYSE). Nevertheless, in a number of areas, the resulting rules are expected to have direct or indirect impacts on our businesses.

Dodd-Frank provisions will increase required disclosures regarding executive compensation, and rules adopted by the SEC in January 2011 require an advisory vote by shareholders on executive compensation ("say-on-pay") and require an advisory vote by shareholders on the frequency that such say-on-pay votes will be submitted in future years at our 2011 annual meeting. New rules adopted by the SEC, which would not apply to us until 2012, are intended to provide shareholders with access to the director nomination process, but those rules have been stayed by the SEC in light of pending legal challenges.

Although Dodd-Frank includes significant new provisions regarding the regulation of derivatives, the impact of those requirements will not be known definitively until regulations have been adopted by the SEC and the CFTC. The SEC is charged with adopting new regulations regarding securitization transactions such as the asset-backed securitizations CenterPoint Houston has sponsored for recovery of transition and storm restoration costs. Dodd-Frank also includes new whistleblower provisions.

Dodd-Frank also makes substantial changes to the regulatory oversight of the credit rating agencies that are typically engaged to rate our securities and those of our subsidiaries. It is presently unknown what effect implementation of these new provisions ultimately will have on the activities or costs associated with the credit rating process.

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CERTAIN FACTORS AFFECTING FUTURE EARNINGS

Our past earnings and results of operations are not necessarily indicative of our future earnings and results of operations. The magnitude of our future earnings and results of our operations will depend on or be affected by numerous factors including:

- the resolution of the true-up proceedings, including, in particular, the results of appeals to the Texas Supreme Court regarding rulings obtained to date;
- state and federal legislative and regulatory actions or developments relating to the environment, including those related to global climate change;
- other state and federal legislative and regulatory actions or developments affecting various aspects of our business, including, among others, energy deregulation or re-regulation, pipeline safety, health care reform, financial reform and tax legislation;
- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;
- the timing and outcome of any audits, disputes and other proceedings related to taxes;
- problems with construction, implementation of necessary technology or other issues with respect to major capital projects that result in delays or in cost overruns that cannot be recouped in rates;
- industrial, commercial and residential growth in our service territory and changes in market demand, including the effects of energy efficiency measures and demographic patterns;
- the timing and extent of changes in commodity prices, particularly natural gas and natural gas liquids, and the effects of geographic and seasonal commodity price differentials;
- the timing and extent of changes in the supply of natural gas, including supplies available for gathering by our field services business and transporting by our interstate pipelines;
- weather variations and other natural phenomena;
- the impact of unplanned facility outages;
- timely and appropriate regulatory actions allowing securitization or other recovery of costs associated with any future hurricanes or natural disasters;
- changes in interest rates or rates of inflation;
- commercial bank and financial market conditions, our access to capital, the cost of such capital, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;
- actions by rating agencies;
- effectiveness of our risk management activities;
- inability of various counterparties to meet their obligations to us;

- non-payment for our services due to financial distress of our customers;

- the ability of GenOn Energy, Inc. (GenOn) (formerly known as RRI Energy, Inc., Reliant Energy, Inc. and Reliant Resources, Inc.) and its subsidiaries to satisfy their obligations to us, including indemnity obligations, or in connection with the contractual arrangements pursuant to which we are their guarantor;

- the ability of REPs, including REP subsidiaries of NRG Retail LLC and REP subsidiaries of TXU Energy Retail Company LLC, which are CenterPoint Houston's two largest customers, to satisfy their obligations to us and our subsidiaries;

- the outcome of litigation brought by or against us;
- our ability to control costs;
- the investment performance of our pension and postretirement benefit plans;
- our potential business strategies, including restructurings, acquisitions or dispositions of assets or businesses, which we cannot assure will be completed or will have the anticipated benefits to us;
- acquisition and merger activities involving us or our competitors; and
- other factors we discuss under “Risk Factors” in Item 1A of this report and in other reports we file from time to time with the Securities and Exchange Commission.

CONSOLIDATED RESULTS OF OPERATIONS

All dollar amounts in the tables that follow are in millions, except for per share amounts.

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 11,322	$ 8,281	$ 8,785
Expenses	10,049	7,157	7,536
Operating Income	1,273	1,124	1,249
Gain (Loss) on Marketable Securities	(139)	82	67
Gain (Loss) on Indexed Debt Securities	128	(68)	(31)
Interest and Other Finance Charges	(468)	(513)	(481)
Interest on Transition and System Restoration Bonds	(136)	(131)	(140)
Equity in Earnings of Unconsolidated Affiliates	51	15	29
Other Income, net	14	39	12
Income Before Income Taxes	723	548	705
Income Tax Expense	(277)	(176)	(263)
Net Income	$ 446	$ 372	$ 442
Basic Earnings Per Share	$ 1.32	$ 1.02	$ 1.08
Diluted Earnings Per Share	$ 1.30	$ 1.01	$ 1.07

2010 Compared to 2009

Net Income. We reported net income of $442 million ($1.07 per diluted share) for 2010 compared to $372 million ($1.01 per diluted share) for the same period in 2009. The increase in net income of $70 million was primarily due to a $125 million increase in operating income, a $37 million decrease in the loss on our indexed debt securities, a $32 million decrease in interest expense due to lower levels of debt, excluding transition and system restoration bond-related interest expense, and a $14 million increase in equity in earnings of unconsolidated affiliates, which were partially offset by an $87 million increase in income tax expense, a $27 million decrease in Other Income, net primarily due to the $23 million of carrying costs related to Hurricane Ike restoration costs in 2009, a $15 million decrease in the gain on our marketable securities and a $9 million increase in interest expense on transition and system restoration bonds.

Income Tax Expense. Our 2010 effective tax rate of 37.3% differed from the 2009 effective tax rate of 32.1% primarily due to the settlement in 2009 of our federal income tax return examinations for tax years 2004 and 2005 and a reduction in state income taxes in 2009 related to adjustments in prior years' state estimates. The 2010 effective tax rate included the effects of remeasuring accumulated deferred income taxes associated with the restructuring of certain subsidiaries in December 2010 (decrease in income tax expense of $24 million) as well as a change in tax law upon the enactment in March 2010 of the Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act of 2010 (increase in income tax expense of $21 million). In combination, these 2010 events did not have a material impact on our 2010 effective tax rate. For more information, see Note 12 to our consolidated financial statements.

2009 Compared to 2008

Net Income. We reported net income of $372 million ($1.01 per diluted share) for 2009 compared to $446 million ($1.30 per diluted share) for the same period in 2008. The decrease in net income of $74 million was primarily due to a $149 million decrease in operating income, a $45 million increase in interest expense due primarily to higher interest rates and higher levels of debt during 2009, excluding transition and system restoration bond-related interest expense, a $36 million decrease in equity in earnings of unconsolidated affiliates and a $196 million decrease in the gain on our indexed debt securities. These decreases in net income were partially offset by a $101 million decrease in income tax expense, a $221 million increase in the gain on our marketable securities, $23 million of carrying costs related to Hurricane Ike restoration costs included in Other Income, net and a $5 million decrease in interest expense on transition and system restoration bonds.

Income Tax Expense. Our 2009 effective tax rate of 32.1% differed from the 2008 effective tax rate of 38.4% primarily due to the settlement in 2009 of our federal income tax return examinations for tax years 2004 and 2005 and a reduction in state income taxes in 2009 related to adjustments in prior years' state estimates. For more information, see Note 12 to our consolidated financial statements.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for 2008, 2009 and 2010. Included in revenues are intersegment sales. We account for intersegment sales as if the sales were to third parties, that is, at current market prices.

Operating Income by Business Segment

	Year Ended December 31,		
	2008	2009	2010
Electric Transmission & Distribution	$ 545	$ 545	$ 567
Natural Gas Distribution	215	204	231
Competitive Natural Gas Sales and Services	62	21	16
Interstate Pipelines	293	256	270
Field Services	147	94	151
Other Operations	11	4	14
Total Consolidated Operating Income	$ 1,273	$ 1,124	$ 1,249

Electric Transmission & Distribution

The following tables provide summary data of our Electric Transmission & Distribution business segment, CenterPoint Houston, for 2008, 2009 and 2010 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2008	2009	2010
Revenues:			
Electric transmission and distribution utility	$ 1,593	$ 1,673	$ 1,768
Transition and system restoration bond companies	323	340	437
Total revenues	1,916	2,013	2,205
Expenses:			
Operation and maintenance, excluding transition and system restoration bond companies	703	774	841
Depreciation and amortization, excluding transition and system restoration bond companies	277	277	293
Taxes other than income taxes	201	208	207
Transition and system restoration bond companies	190	209	297
Total expenses	1,371	1,468	1,638
Operating Income	$ 545	$ 545	$ 567
Operating Income:			
Electric transmission and distribution operations	$ 407	$ 414	$ 427
Competition transition charge	5	—	—
Transition and system restoration bond companies (1)	133	131	140
Total segment operating income	$ 545	$ 545	$ 567
Throughput (in gigawatt-hours (GWh)):			
Residential	24,258	24,815	26,554
Total	74,840	74,579	76,973
Number of metered customers at end of period:			
Residential	1,821,267	1,849,019	1,874,508
Total	2,064,854	2,094,210	2,122,135

(1) Represents the amount necessary to pay interest on the transition and system restoration bonds.

2010 Compared to 2009. Our Electric Transmission & Distribution business segment reported operating income of $567 million for 2010, consisting of $427 million from our regulated electric transmission and distribution utility operations (TDU) and $140 million related to transition and system restoration bond companies. For 2009, operating income totaled $545 million, consisting of $414 million from the TDU and $131 million related to transition and system restoration bond companies. TDU revenues increased $95 million primarily due to increased revenues from implementation of AMS ($34 million), increased usage ($30 million), in part caused by favorable weather, higher transmission-related revenues ($26 million) and higher revenues due to customer growth ($20 million) from the addition of nearly 28,000 new customers, partially offset by a customer credit related to deferred income taxes associated with Hurricane Ike storm restoration costs ($21 million). Operation and maintenance expenses increased $67 million primarily due to higher transmission costs billed by transmission providers ($28 million), increased AMS project expenses ($11 million), increased labor costs ($10 million), increased contracts and services ($10 million) and increased environmental remediation costs ($7 million). Increased depreciation expense is related to increased investment in AMS ($19 million).

2009 Compared to 2008. Our Electric Transmission & Distribution business segment reported operating income of $545 million for 2009, consisting of $414 million from the TDU and $131 million related to transition and system restoration bond companies. For 2008, operating income totaled $545 million, consisting of $407 million from the TDU, exclusive of an additional $5 million from the competition transition charge, and $133 million related to transition bond companies. Revenues for the TDU increased due to higher transmission-related revenues ($50 million), in part reflecting the impact of a transmission rate increase implemented in November 2008, the impact of Hurricane Ike in 2008 ($17 million), revenues from implementation of AMS ($33 million) and higher revenues due to customer growth ($17 million) from the addition of over 29,000 new customers, partially offset by declines in energy demand ($27 million). Operation and maintenance expenses increased $71 million primarily due to higher transmission costs billed by transmission providers ($18 million), increased operating and maintenance expenses that were postponed in 2008 as a result of Hurricane Ike restoration efforts ($10 million), higher pension and other employee benefit costs ($10 million), expenses related to AMS ($14 million) and a gain on a land sale in 2008 ($9 million). Increased depreciation expense related to increased investment in AMS ($7 million) was offset by other declines in depreciation and amortization, primarily due to asset retirements. Taxes other than income taxes increased $7 million primarily as a result of a refund in 2008 of prior years' state franchise taxes ($5 million). Changes in pension expense over our 2007 base year amount were deferred and included in our 2010 rate filing pursuant to Texas law.

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2008, 2009 and 2010 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 4,226	$ 3,384	$ 3,213
Expenses:			
Natural gas	3,124	2,251	2,049
Operation and maintenance	589	639	639
Depreciation and amortization	157	161	166
Taxes other than income taxes	141	129	128
Total expenses	4,011	3,180	2,982
Operating Income	$ 215	$ 204	$ 231
Throughput (in Bcf):			
Residential	175	173	177
Commercial and industrial	236	233	249
Total Throughput	411	406	426
Number of customers at end of period:			
Residential	2,987,222	3,002,114	3,016,333
Commercial and industrial	248,476	244,101	246,891
Total	3,235,698	3,246,215	3,263,224

2010 Compared to 2009. Our Natural Gas Distribution business segment reported operating income of $231 million for 2010 compared to $204 million for 2009. Operating income increased $27 million primarily as a result of revenue from base rate increases and annual rate adjustments ($24 million), lower pension and other benefits costs ($14 million), customer growth, higher throughput and increased other revenues ($8 million) and lower bad debt expense ($5 million). These were partially offset by higher labor costs ($7 million), higher contracts and services ($5 million) and other expenses ($7 million). Depreciation and amortization expense increased $5 million primarily due to higher plant balances.

2009 Compared to 2008. Our Natural Gas Distribution business segment reported operating income of $204 million for 2009 compared to $215 million for 2008. Operating income declined ($11 million) primarily as a result of increased pension expense ($37 million) and higher labor and other benefit costs ($16 million), partially offset by increased revenues from rate increases ($36 million) and lower bad debt expense ($15 million). Revenues related to both energy-efficiency costs and gross receipts taxes are substantially offset by the related expenses. Depreciation and amortization expense increased $4 million primarily due to higher plant balances. Taxes other than income taxes, net of the decrease in gross receipts taxes ($16 million), increased $4 million also primarily due to higher plant balances.

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Competitive Natural Gas Sales and Services

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for 2008, 2009 and 2010 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 4,528	$ 2,230	$ 2,651
Expenses:			
Natural gas	4,423	2,165	2,591
Operation and maintenance	39	39	38
Depreciation and amortization	3	4	4
Taxes other than income taxes	1	1	2
Total expenses	4,466	2,209	2,635
Operating Income	$ 62	$ 21	$ 16
Throughput (in Bcf)	528	504	548
Number of customers at end of period	9,771	11,168	12,193

2010 Compared to 2009. Our Competitive Natural Gas Sales and Services business segment reported operating income of $16 million for 2010 compared to $21 million for 2009. The decrease in operating income of $5 million was primarily due to reduced basis spreads on pipeline transport opportunities and decreased seasonal storage spreads of $32 million as compared to last year. Offsetting this decrease to operating income is an increase in operating income of $27 million related to the favorable impact of the mark-to-market valuation for non-trading financial derivatives for 2010 of $4 million versus the unfavorable impact of $23 million for 2009. Additionally, a $6 million write-down of natural gas inventory to the lower of cost or market occurred in both 2009 and 2010.

2009 Compared to 2008. Our Competitive Natural Gas Sales and Services business segment reported operating income of $21 million for 2009 compared to $62 million for 2008. The decrease in operating income of $41 million was due to the unfavorable impact of the mark-to-market valuation for non-trading financial derivatives for 2009 of $23 million versus a favorable impact of $13 million for the same period in 2008. A further $28 million decrease in margin is attributable to reduced basis spreads on pipeline transport opportunities and an absence of summer storage spreads. These decreases in operating income were partially offset by a $6 million write-down of natural gas inventory to the lower of cost or market for 2009 compared to a $30 million write-down in the same period in 2008. Our Competitive Natural Gas Sales and Services business segment purchases and stores natural gas to meet certain future sales requirements and enters into derivative contracts to hedge the economic value of the future sales.

Interstate Pipelines

The following table provides summary data of our Interstate Pipelines business segment for 2008, 2009 and 2010 (in millions, except throughput data):

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 650	$ 598	$ 601
Expenses:			
Natural gas	155	97	93
Operation and maintenance	133	166	153
Depreciation and amortization	46	48	52
Taxes other than income taxes	23	31	33
Total expenses	357	342	331
Operating Income	$ 293	$ 256	$ 270
Equity in earnings of unconsolidated affiliates	$ 36	$ 7	$ 19
Transportation throughput (in Bcf)	1,538	1,592	1,693

2010 Compared to 2009. Our Interstate Pipeline business segment reported operating income of $270 million for 2010 compared to $256 million for 2009. Margins (revenues less natural gas costs) increased by $7 million primarily due to new contracts for the Phase IV Carthage to Perryville pipeline expansion ($42 million) and new power plant transportation contracts ($4 million), partially offset by reduced ancillary services, off-system and other transportation margins ($39 million). Lower operation and maintenance expenses ($13 million) were partially offset by increased depreciation and amortization expenses ($4 million) related to new assets and increased taxes other than income taxes ($2 million).

2009 Compared to 2008. Our Interstate Pipeline business segment reported operating income of $256 million for 2009 compared to $293 million for 2008. Margins increased $6 million primarily due to the Carthage to Perryville pipeline ($28 million) and new contracts with power generation customers ($20 million), partially offset by reduced other transportation margins and ancillary services ($42 million) primarily due to the decline in commodity prices from the significantly higher levels in 2008. Operations and maintenance expenses increased due to a gain on the sale of two storage development projects in 2008 ($18 million) and costs associated with incremental facilities ($12 million) and increased pension expenses ($9 million). These expenses were partially offset by a write-down associated with pipeline assets removed from service in the third quarter of 2008 ($7 million). Depreciation and amortization expenses increased $2 million and taxes other than income taxes increased by $8 million, $2 million of which was due to 2008 tax refunds.

Equity Earnings. In addition, this business segment recorded equity income of $36 million, $7 million and $19 million in the years ended December 31, 2008, 2009 and 2010, respectively, from its 50% interest in SESH, a jointly-owned pipeline. The 2008 year-end results include $33 million of pre-operating allowance for funds used during construction. The 2009 results include a non-cash pre-tax charge of $16 million to reflect SESH’s decision to discontinue the use of guidance for accounting for regulated operations, which was partially offset by the receipt of a one-time payment related to the construction of the pipeline and a reduction in estimated property taxes, of which our 50% share was $5 million. Excluding the effect of these adjustments, equity earnings from normal operations was $3 million and $18 million in 2008 and 2009, respectively. These amounts are included in Equity in Earnings of Unconsolidated Affiliates under the Other Income (Expense) caption in the Statements of Consolidated Income.

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Field Services

The following table provides summary data of our Field Services business segment for 2008, 2009 and 2010 (in millions, except throughput data):

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 252	$ 241	$ 338
Expenses:			
Natural gas	21	51	72
Operation and maintenance	69	77	85
Depreciation and amortization	12	15	25
Taxes other than income taxes	3	4	5
Total expenses	105	147	187
Operating Income	$ 147	$ 94	$ 151
Equity in earnings of unconsolidated affiliates	$ 15	$ 8	$ 10
Gathering throughput (in Bcf)	421	426	650

2010 Compared to 2009. Our Field Services business segment reported operating income of $151 million for 2010 compared to $94 million for 2009. Margins (revenues less natural gas costs) increased primarily due to new projects, including the Magnolia and Olympia Gathering Systems in the North Louisiana Haynesville Shale and core gathering services ($74 million), along with increased commodity prices ($2 million). Increases in operating expenses ($29 million) and depreciation ($10 million) associated with new projects were partially offset by a gain on the sale of non-strategic gathering assets in October 2010 ($21 million).

2009 Compared to 2008. Our Field Services business segment reported operating income of $94 million for 2009 compared to $147 million for 2008. Margins from new projects and core gathering services increased approximately $24 million for 2009 when compared to the same period in 2008 primarily due to continued development in the shale plays. This increase was offset primarily by the effect of a decline in commodity prices of approximately $54 million from the significantly higher prices experienced in 2008. Operating income for 2009 also included higher costs associated with incremental facilities ($4 million) and increased pension cost ($2 million). Operating income for 2008 benefited from a one-time gain ($11 million) related to a settlement and contract buyout of one of our customers and a gain on sale of assets ($6 million).

Equity Earnings. In addition, this business segment recorded equity income of $15 million, $8 million and $10 million for the years ended December 31, 2008, 2009 and 2010, respectively, from its 50% interest in Waskom. The increase is driven primarily by assets acquired in the first quarter of 2010, higher natural gas liquid prices, partially offset by lower processing volumes. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption in the Statements of Consolidated Income.

Other Operations

The following table provides summary data for our Other Operations business segment for 2008, 2009 and 2010 (in millions):

Year Ended December 31,

	2008	2009	2010
Revenues	$ 11	$ 11	$ 11
Expenses	–	7	(3)
Operating Income	$ 11	$ 4	$ 14

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flows

The net cash provided by (used in) operating, investing and financing activities for 2008, 2009 and 2010 is as follows (in millions):

	Year Ended December 31,		
	2008	2009	2010
Cash provided by (used in):			
Operating activities	$ 851	$ 1,841	$ 1,386
Investing activities	(1,368)	(896)	(1,420)
Financing activities	555	(372)	(507)

Cash Provided by Operating Activities

Net cash provided by operating activities in 2010 decreased $455 million compared to 2009 primarily due to decreased cash related to gas storage inventory ($274 million), increased tax payments ($216 million) and increased net margin deposits ($109 million), which were partially offset by increased income ($70 million), increased cash provided by net accounts receivable/payable ($21 million) and increased cash provided by net regulatory assets and liabilities ($14 million).

Net cash provided by operating activities in 2009 increased $990 million compared to 2008 primarily due to decreased cash used in net regulatory assets and liabilities primarily related to Hurricane Ike restoration costs in 2008 ($366 million), decreased cash used in net margin deposits ($298 million), decreased cash used in gas storage inventory ($246 million) and increased cash provided by net accounts receivable/payable ($41 million).

Cash Used in Investing Activities

Net cash used in investing activities increased $524 million in 2010 compared to 2009 due to increased capital expenditures ($349 million), primarily related to Field Services projects ($320 million), decreased cash from notes receivable from unconsolidated affiliates ($323 million) and increased restricted cash of transition bond and system restoration companies ($31 million), which were partially offset by decreased investment in unconsolidated affiliates ($97 million) and cash received from the DOE grant ($90 million).

Net cash used in investing activities decreased $472 million in 2009 compared to 2008 due to decreased notes receivable from unconsolidated affiliates ($498 million), decreased investment in unconsolidated affiliates ($91 million) and decreased restricted cash of transition bond companies ($37 million) offset by increased capital expenditures ($140 million) primarily related to our Field Services business segment.

Cash Provided by (Used in) Financing Activities

Net cash used in financing activities in 2010 increased $135 million compared to 2009 primarily due to decreased proceeds from long-term debt ($1.2 billion), increased payments of long-term debt ($561 million), decreased proceeds from the issuance of common stock ($88 million) and increased common stock dividend payments ($43 million), which were offset by decreased repayments of borrowings under revolving credit facilities ($1.4 billion), increased proceeds from commercial paper ($183 million) and increased short-term debt borrowings ($96 million).

Net cash used in financing activities in 2009 increased $927 million compared to 2008 primarily due to decreased borrowings under revolving credit facilities ($2.6 billion), and decreased short-term borrowings ($19 million), which were partially offset by decreased repayments of long-term debt ($1.2 billion), increased proceeds from the issuance of common stock ($424 million) and increased proceeds from the issuance of long-term debt ($77 million).

Future Sources and Uses of Cash

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, tax payments, working capital needs, various regulatory actions and appeals relating to such regulatory actions. Our principal anticipated cash requirements for 2011 include the following:

- approximately $1.3 billion of capital expenditures;
- maturing long-term debt aggregating approximately $19 million, excluding $550 million aggregate principal amount of CERC Corp. debt that was retired at its maturity in February 2011 with proceeds from debt issued by CERC Corp. in January 2011;
- $283 million of scheduled principal payments on transition and system restoration bonds; and
- dividend payments on CenterPoint Energy common stock and interest payments on debt.

We expect that cash on hand, borrowings under our credit facilities, proceeds from commercial paper and anticipated cash flows from operations will be sufficient to meet our anticipated cash needs in 2011. Cash needs or discretionary financing or refinancing may result in the issuance of equity or debt securities in the capital markets or the arrangement of additional credit facilities. Issuances of equity or debt in the capital markets, funds raised in the commercial paper markets and additional credit facilities may not, however, be available to us on acceptable terms.

The following table sets forth our capital expenditures for 2010 and estimates of our capital expenditures for 2011 through 2015 (in millions):

	2010	2011	2012	2013	2014	2015
Electric Transmission & Distribution (1)	$ 463	$ 605	$ 468	$ 469	$ 506	$ 372
Natural Gas Distribution	202	263	274	285	285	285
Competitive Natural Gas Sales and Services	2	10	12	12	6	6
Interstate Pipelines	102	157	133	131	119	95
Field Services	668	262	135	125	59	60
Other Operations	25	40	31	25	25	27
Total	$ 1,462	$ 1,337	$ 1,053	$ 1,047	$ 1,000	$ 845

(1) Includes capital expenditures of $119 million in 2010 and estimated capital expenditures of $225 million, $64 million and $10 million in 2011, 2012 and 2013, respectively, related to AMS and IG, net of a $200 million grant by the DOE.

The following table sets forth estimates of our contractual obligations, including payments due by period (in millions):

Contractual Obligations	Total	2011	2012-2013	2014-2015	2016 and thereafter
Transition and system restoration bond debt	$ 2,805	$ 283	$637	$484	$ 1,401
Other long-term debt(1)	7,303	19	1,044	1,380	4,860
Interest payments — transition and system restoration bond debt(2)	699	129	217	162	191
	4,195	426	790	562	2,417

Interest payments — other long-term debt(2)								
Short-term borrowings		53		53	—	—		—
Capital leases		1		—	—	—		1
Operating leases(3)		59		15	19	10		15
Benefit obligations(4)		—		—	—	—		—
Purchase obligations(5)		1		1	—	—		—
Non-trading derivative liabilities		85		69	16	—		—
Other commodity commitments(6)		2,393		502	933	505		453
Income taxes(7)		—		—	—	—		—
Other		18		6	12	—		—
Total contractual cash obligations	$	17,612	$	1,503	$3,668	$3,103	$	9,338

(1) 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS) obligations are included in the 2016 and thereafter column at their contingent principal amount payable in 2029 of $805 million. These obligations are exchangeable for cash at any time at the option of the holders for 95% of the current value of the reference shares attributable to each ZENS ($367 million at December 31, 2010), as discussed in Note 9 to our consolidated financial statements. Maturities in 2011 exclude $550 million of 7.75% senior notes of CERC Corp. and maturities in 2013 exclude $397 million of 7.875% senior notes of CERC Corp. discussed in Note 11(b) to our consolidated financial statements and below under " –Debt Financing Transactions."

(2) We calculated estimated interest payments for long-term debt as follows: for fixed-rate debt and term debt, we calculated interest based on the applicable rates and payment dates; for variable-rate debt and/or non-term debt, we used interest rates in place as of December 31, 2010. We typically expect to settle such interest payments with cash flows from operations and short-term borrowings.

(3) For a discussion of operating leases, please read Note 13(c) to our consolidated financial statements.

(4) We expect to make a minimum required contribution of $35 million in 2011 to our qualified pension plan. We expect to contribute approximately $9 million and $18 million, respectively, to our non-qualified pension and postretirement benefits plans in 2011.

(5) Represents capital commitments for material in connection with our Interstate Pipelines business segment.

(6) For a discussion of other commodity commitments, please read Note 13(a) to our consolidated financial statements.

(7) As of December 31, 2010, the liability for uncertain income tax positions was $252 million. However, due to the high degree of uncertainty regarding the timing of potential future cash flows associated with these liabilities, we are unable to make a reasonably reliable estimate of the amount and period in which any such liabilities might be paid.

Off-Balance Sheet Arrangements. Other than the guaranties described below and operating leases, we have no off-balance sheet arrangements.

Prior to the distribution of our ownership in RRI to our 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 (now GenOn) 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 based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $112 million as of December 31, 2010. Market conditions in the fourth quarter of 2010 required posting of security under the agreement, and GenOn posted approximately $7 million in collateral in December 2010. If GenOn 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.

In May 2009, RRI sold its Texas retail business to NRG Retail, a subsidiary of NRG Energy, Inc. In December 2010, Mirant Corporation merged with and became a wholly owned subsidiary of RRI and RRI changed its name from RRI Energy, Inc. to GenOn Energy, Inc. Neither the sale of the retail business nor the merger with Mirant Corporation alters GenOn's contractual obligations to indemnify us and our subsidiaries, including CenterPoint Houston, for certain liabilities, including their indemnification obligations regarding certain litigation, nor does it affect the terms of existing guaranty arrangements for certain GenOn gas transportation contracts.

Debt Financing Transactions. In January 2010, we purchased $290 million principal amount of pollution control bonds issued on our behalf at 101% of their principal amount plus accrued interest pursuant to the mandatory tender provisions of the bonds. Prior to the purchase, the pollution control bonds had a fixed rate of interest of 5.125%. The purchase reduced temporary investments and leverage while providing us with the flexibility to finance future capital needs in the tax-exempt market through a remarketing of these bonds.

In January 2010, CERC Corp. redeemed $45 million of its outstanding 6% convertible subordinated debentures due 2012 at 100% of the principal amount plus accrued and unpaid interest to the redemption date.

In September 2010, we repaid $200 million principal amount of 7.25% senior notes on their maturity date.

In January 2011, CERC Corp. issued $250 million aggregate principal amount of senior notes due 2021 with an interest rate of 4.50% and $300 million aggregate principal amount of senior notes due 2041 with an interest rate of 5.85%. The proceeds from the issuance of the notes were used for the repayment of $550 million of CERC Corp.'s 7.75% senior notes at their maturity in February 2011.

Also in January 2011, CERC Corp. issued an additional $343 million aggregate principal amount of 4.50% senior notes due 2021 and provided cash consideration of $114 million in exchange for $397 million aggregate principal amount of its 7.875% senior notes due 2013. The premium of $58 million paid on exchanged notes has been deferred and will be amortized to interest expense over the life of the 4.50% senior notes due 2021.

Equity Financing Transactions. During the year ended December 31, 2010, we received net proceeds of approximately $315 million from the issuance of 25.3 million common shares in an underwritten public offering, proceeds of approximately $79 million from the sale of approximately 5.4 million common shares to our defined contribution plan and proceeds of approximately $15 million from the sale of approximately 1.0 million common shares to participants in our enhanced dividend reinvestment plan. In January 2011, we suspended the issuance of common shares to our defined contribution plan and our enhanced dividend reinvestment plan. Common shares for the two plans are now being purchased on the open market.

Credit and Receivables Facilities. In September 2010, CERC amended its 364-day receivables facility to extend the termination date to September 14, 2011. Availability under CERC's receivables facility ranges from $160 million to $375 million, reflecting seasonal changes in receivables balances. As of December 31, 2009 and 2010, the facility size was $150 million and $160 million, respectively. As of both December 31, 2009 and 2010, there were no advances under the receivables facility.

As of February 15, 2011, we had the following facilities (in millions):

Date Executed	Company	Type of Facility	Size of Facility	Amount Utilized at February 15, 2011 (1)		Termination Date
June 29, 2007	CenterPoint Energy	Revolver	$ 1,156	$ 20	(2)	June 29, 2012
June 29, 2007	CenterPoint Houston	Revolver	289	4	(2)	June 29, 2012
June 29, 2007	CERC Corp.	Revolver	915	248	(3)	June 29, 2012
September 15, 2010	CERC	Receivables	375	—		September 14, 2011

(1) Based on the debt (excluding transition and system restoration bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant contained in our $1.2 billion credit facility, we would have

been permitted to utilize the full capacity of our credit facilities of $2.4 billion at December 31, 2010. Amounts advanced under CERC's receivables facility are not treated as outstanding indebtedness in the debt to EBITDA covenant calculation.

(2) Represents outstanding letters of credit.

(3) Represents commercial paper that is backstopped by CERC Corp.'s revolving credit facility.

Our $1.2 billion credit facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on our current credit ratings. The facility contains a debt (excluding transition and system restoration bonds) to EBITDA covenant (as those terms are defined in the facility). In February 2010, we amended our credit facility to modify the covenant to allow for a temporary increase of the permitted ratio from 5 times to 5.5 times if CenterPoint Houston experiences damage from a natural disaster in its service territory and we certify 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 we deliver our certification until the earliest to occur of (i) the completion of the securitization financing, (ii) the first anniversary of our certification or (iii) the revocation of such certification.

CenterPoint Houston's $289 million credit facility contains a debt (excluding transition and system restoration bonds) to total capitalization covenant, limiting debt to 65% of its total capitalization. The facility's first drawn cost is LIBOR plus 45 basis points based on CenterPoint Houston's current credit ratings.

CERC Corp.'s $915 million credit facility's first drawn cost is LIBOR plus 45 basis points based on CERC Corp.'s current credit ratings. The facility contains a debt to total capitalization covenant, limiting debt to 65% of its total capitalization.

Under our $1.2 billion credit facility, CenterPoint Houston's $289 million credit facility and CERC Corp's $915 million credit facility, 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.

Borrowings under each of the facilities are subject to customary terms and conditions. However, there is no requirement that we, CenterPoint Houston or CERC Corp. make representations prior to borrowings as to the absence of material adverse changes or litigation that could be expected to have a material adverse effect. Borrowings under each of the credit facilities are subject to acceleration upon the occurrence of events of default that we, CenterPoint Houston or CERC Corp. consider customary.

We, CenterPoint Houston and CERC Corp. are currently in compliance with the various business and financial covenants contained in the respective credit facilities as disclosed above.

Our $1.2 billion credit facility backstops a $1.0 billion CenterPoint Energy commercial paper program under which we began issuing commercial paper in June 2005. The $915 million CERC Corp. credit facility backstops a $915 million commercial paper program under which CERC Corp. began issuing commercial paper in February 2008. As of December 31, 2010, CERC Corp. had $183 million of outstanding commercial paper. As a result of the credit ratings on the two commercial paper programs, we do not expect to be able to rely on the sale of commercial paper to fund all of our short-term borrowing requirements.

During 2010, CERC met substantially all of its liquidity requirements with borrowings from the money pool described below under "—Money Pool." During the fourth quarter of 2010, CERC also met a portion of its liquidity requirements with commercial paper proceeds. We currently expect that CERC may be required to access financing sources, in addition to money pool borrowings, in order to satisfy its liquidity requirements in 2011. These sources could include commercial paper proceeds or borrowings under CERC Corp.'s revolving credit or receivables facilities.

Securities Registered with the SEC. CenterPoint Energy, CenterPoint Houston and CERC Corp. have filed a joint shelf registration statement with the SEC registering indeterminate principal amounts of CenterPoint Houston's general mortgage bonds, CERC Corp.'s senior debt securities and CenterPoint Energy's senior debt securities and junior subordinated debt securities and an indeterminate number of CenterPoint Energy's shares of common stock, shares of preferred stock, as well as stock purchase contracts and equity units.

Temporary Investments. As of February 15, 2011, we had no external temporary investments.

Money Pool. We have a money pool through which the holding company and participating subsidiaries can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the money pool are expected to be met with borrowings under our revolving credit facility or the sale of our commercial paper.

Impact on Liquidity of a Downgrade in Credit Ratings. The interest on borrowings under our credit facilities is based on our credit rating. As of February 15, 2011, Moody's Investors Service, Inc. (Moody's), Standard & Poor's Rating Services (S&P), a division of The McGraw-Hill Companies, and Fitch, Inc. (Fitch) had assigned the following credit ratings to senior debt of CenterPoint Energy and certain subsidiaries:

	Moody's		S&P		Fitch	
Company/Instrument	Rating	Outlook (1)	Rating	Outlook(2)	Rating	Outlook(3)
CenterPoint Energy Senior Unsecured Debt	Ba1	Positive	BBB-	Stable	BBB-	Stable
CenterPoint Houston Senior Secured Debt	A3	Stable	BBB+	Stable	A-	Stable
CERC Corp. Senior Unsecured Debt	Baa3	Positive	BBB	Stable	BBB	Stable

(1) A Moody's rating outlook is an opinion regarding the likely direction of a rating over the medium term.

(2) An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate to longer term.

(3) A "stable" outlook from Fitch encompasses a one- to two-year horizon as to the likely ratings direction.

We cannot assure you that the ratings set forth above will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are included for informational purposes and are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing, the cost of such financings and the execution of our commercial strategies.

A decline in credit ratings could increase borrowing costs under our $1.2 billion credit facility, CenterPoint Houston's $289 million credit facility and CERC Corp.'s $915 million credit facility. If our credit ratings or those of CenterPoint Houston or CERC had been downgraded one notch by each of the three principal credit rating agencies from the ratings that existed at December 31, 2010, the impact on the borrowing costs under our bank credit facilities would have been immaterial. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions and to access the commercial paper markets.

CERC Corp. and its subsidiaries purchase natural gas from one of their suppliers under supply agreements that contain an aggregate credit threshold of $120 million based on CERC Corp.'s S&P senior unsecured long-term debt rating of BBB. Under these agreements, CERC may need to provide collateral if the aggregate threshold is exceeded. Upgrades and downgrades from this BBB rating will increase and decrease the aggregate credit threshold accordingly.

CenterPoint Energy Services, Inc. (CES), a wholly owned subsidiary of CERC Corp. operating in our Competitive Natural Gas Sales and Services business segment, provides comprehensive natural gas sales and services primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. In order to economically hedge its exposure to natural gas prices, CES uses derivatives with provisions standard for the industry, including those pertaining to credit thresholds. Typically, the credit threshold negotiated with each counterparty defines the amount of unsecured credit that such counterparty will extend to CES. To the extent that the credit exposure that a counterparty has to CES at a particular time does not exceed that credit threshold, CES is not obligated to provide collateral. Mark-to-market exposure in excess of the credit threshold is routinely collateralized by CES. As of December 31, 2010, the amount posted as collateral aggregated approximately $107 million ($59 million of which is associated with price stabilization activities of our Natural Gas Distribution business segment). Should the credit ratings of CERC Corp. (as the credit support provider for CES) fall below certain levels, CES would be required to provide additional collateral up to the amount of its previously unsecured credit limit. We estimate that as of December 31, 2010, unsecured credit limits extended to CES by counterparties aggregate $248 million; however, utilized credit capacity was $79 million.

Pipeline tariffs and contracts typically provide that if the credit ratings of a shipper or the shipper's guarantor drop below a threshold level, which is generally investment grade ratings from both Moody's and S&P, cash or other collateral may be demanded from the shipper in an amount equal to the sum of three months' charges for pipeline services plus the unrecouped cost of any lateral built for such shipper. If the credit ratings of CERC Corp. decline below the applicable threshold levels, CERC Corp. might need to provide cash or other collateral of as much as $181 million as of December 31, 2010. The amount of collateral will depend on seasonal variations in transportation levels.

In September 1999, we issued ZENS having an original principal amount of $1.0 billion of which $840 million remain outstanding at December 31, 2010. Each ZENS note was originally exchangeable at the holder's option at any time for an amount of cash equal to 95% of the market value of the reference shares of Time Warner Inc. common stock (TW Common) attributable to such note. The number and identity of the reference shares attributable to each ZENS note are adjusted for certain corporate events. As of December 31, 2010, the reference shares for each ZENS note consisted of 0.5 share of TW Common, 0.125505 share of Time Warner Cable Inc. common stock (TWC Common) and 0.045455 share of AOL Inc. common stock (AOL Common). If our creditworthiness were to drop such that ZENS note holders thought our liquidity was adversely affected or the market for the ZENS notes were to become illiquid, some ZENS note holders might decide to exchange their ZENS notes for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of TW Common, TWC Common and AOL Common that we own or from other sources. We own shares of TW Common, TWC Common and AOL Common equal to approximately 100% of the reference shares used to calculate our obligation to the holders of the ZENS notes. ZENS note exchanges result in a cash outflow because tax deferrals related to the ZENS notes and TW Common, TWC Common and AOL Common shares would typically cease when ZENS notes are exchanged or otherwise retired and TW Common, TWC Common and AOL Common shares are sold. The ultimate tax liability related to the ZENS notes continues to increase by the amount of the tax benefit realized each year, and there could be a significant cash outflow when the taxes are paid as a result of the retirement of the ZENS notes.

Cross Defaults. Under our revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $50 million by us or any of our significant subsidiaries will cause a default. In addition, three outstanding series of our senior notes, aggregating $750 million in principal amount as of December 31, 2010, provide that a payment default by us, CERC Corp. or CenterPoint Houston in respect of, or an acceleration of, borrowed money and certain other specified types of obligations, in the aggregate principal amount of $50 million, will cause a default. A default by CenterPoint Energy would not trigger a default under our subsidiaries' debt instruments or bank credit facilities.

Possible Acquisitions, Divestitures and Joint Ventures. From time to time, we consider the acquisition or the disposition of assets or businesses or possible joint ventures or other joint ownership arrangements with respect to assets or businesses. Any determination to take any action in this regard will be based on market conditions and opportunities existing at the time, and accordingly, the timing, size or success of any efforts and the associated potential capital commitments are unpredictable. We may seek to fund all or part of any such efforts with proceeds from debt and/or equity issuances. Debt or equity financing may not, however, be available to us at that time due to a variety of events, including, among others, maintenance of our credit ratings, industry conditions, general economic conditions, market conditions and market perceptions.

Other Factors that Could Affect Cash Requirements. In addition to the above factors, our liquidity and capital resources could be affected by:

- cash collateral requirements that could exist in connection with certain contracts, including our weather hedging arrangements, and gas purchases, gas price and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments;

- acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of natural gas suppliers;

- increased costs related to the acquisition of natural gas;
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various legislative or regulatory actions;
- incremental collateral, if any, that may be required due to regulation of derivatives;
- the ability of GenOn and its subsidiaries to satisfy their obligations in respect of GenOn's indemnity obligations to us and our subsidiaries or in connection with the contractual obligations to a third party pursuant to which CERC is a guarantor;
- the ability of REPs, including REP subsidiaries of NRG Retail LLC and REP subsidiaries of TXU Energy Retail Company LLC, which are CenterPoint Houston's two largest customers, to satisfy their obligations to us and our subsidiaries;
- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- the outcome of litigation brought by and against us;
- contributions to pension and postretirement benefit plans;
- restoration costs and revenue losses resulting from future natural disasters such as hurricanes and the timing of recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Item 1A of this report.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money. CenterPoint Houston's credit facilities limit CenterPoint Houston's debt (excluding transition and system restoration bonds) as a percentage of its total capitalization to 65%. CERC Corp.'s bank facility and its receivables facility limit CERC's debt as a percentage of its total capitalization to 65%. Our $1.2 billion credit facility contains a debt, excluding transition and system restoration bonds, to EBITDA covenant. In February 2010, we amended our $1.2 billion credit facility to modify this covenant to allow for a temporary increase in debt capacity if CenterPoint Houston experiences damage from a natural disaster in its service territory that meets certain criteria. Additionally, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the presentation of our financial condition and results of operations and requires management to make difficult, subjective or complex accounting estimates. An accounting estimate is an approximation made by management of a financial statement element, item or account in the financial statements. Accounting estimates in our historical consolidated financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. The accounting estimates described below require us to make assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that we could have used or changes in an accounting estimate that are reasonably likely to occur could have a material impact on the presentation of our financial condition or results of operations. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be predicted with certainty. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Our significant accounting policies are discussed in Note 2 to our consolidated financial statements. We believe the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the audit committee of the board of directors.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Our Electric Transmission & Distribution business segment, our Natural Gas Distribution business segment and portions of our Interstate Pipelines business segment apply this accounting guidance. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals. If events were to occur that would make the recovery of these assets and liabilities no longer probable, we would be required to write off or write down these regulatory assets and liabilities. At December 31, 2010, we had recorded regulatory assets of $3.4 billion and regulatory liabilities of $989 million.

Impairment of Long-Lived Assets and Intangibles

We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill as required by accounting guidance for goodwill and other intangible assets. No impairment of goodwill was indicated based on our annual analysis at July 1, 2010. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of our assets and result in an impairment charge.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Unbilled Energy Revenues

Revenues related to electricity delivery and natural gas sales and services are generally recognized upon delivery to customers. However, the determination of deliveries to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, deliveries to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Unbilled electricity delivery revenue is estimated each month based on daily supply volumes, applicable rates and analyses reflecting significant historical trends and experience. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Pension and Other Retirement Plans

We sponsor pension and other retirement plans in various forms covering all employees who meet eligibility requirements. We use several statistical and other factors that attempt to anticipate future events in calculating the expense and liability related to our plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. Please read "— Other Significant Matters — Pension Plans" for further discussion.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(o) to our consolidated financial statements for a discussion of new accounting pronouncements that affect us.

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 6(b) to our consolidated financial statements, we maintain a non-contributory qualified defined benefit pension plan covering substantially all employees. Employer contributions for the qualified plan are based on actuarial computations that establish the minimum contribution required under the Employee Retirement Income Security Act of 1974 (ERISA) and the maximum deductible contribution for income tax purposes.

Under the terms of our pension plan, we reserve the right to change, modify or terminate the plan. Our funding policy is to review amounts annually and contribute an amount at least equal to the minimum contribution required under ERISA.

We made no contribution to the qualified pension plan in 2008 or 2010; however, a discretionary contribution of $13 million was made in 2009. The minimum funding requirements for this plan did not require contributions for the respective years. We expect to make a minimum required contribution of $35 million in 2011.

Additionally, we maintain an unfunded non-qualified benefit restoration plan that allows participants to receive the benefits to which they would have been entitled under our non-contributory pension plan except for the federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. Employer contributions for the non-qualified benefit restoration plan represent benefit payments made to participants and totaled $8 million, $7 million and $8 million in 2008, 2009 and 2010, respectively.

Changes in pension obligations and assets may not be immediately recognized as pension expense in the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension expense recorded in any period may not reflect the actual level of benefit payments provided to plan participants.

As the sponsor of a plan, we are required to (a) recognize on our balance sheet as an asset a plan's over-funded status or as a liability such plan's under-funded status, (b) measure a plan's assets and obligations as of the end of our fiscal year and (c) recognize changes in the funded status of our plans in the year that changes occur through adjustments to other comprehensive income.

As of December 31, 2010, the projected benefit obligation exceeded the market value of plan assets of our pension plans by $468 million. Changes in interest rates or the market values of the securities held by the plan during 2011 could materially, positively or negatively, change our funded status and affect the level of pension expense and required contributions.

Pension cost was $1 million, $111 million and $86 million for 2008, 2009 and 2010, respectively, of which $1 million, $60 million and $44 million impacted pre-tax earnings. CenterPoint Houston's actuarially determined pension and other postemployment expenses in excess of the 2007 base year amount are being deferred for rate making purposes until the conclusion of the current general rate case pursuant to Texas law. CenterPoint Houston deferred as a regulatory asset $32 million and $26 million in pension and other postemployment expenses during the years ended December 31, 2009 and 2010, respectively.

The calculation of pension expense and related liabilities requires the use of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. Two of the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate.

As of December 31, 2010, our qualified pension plan had an expected long-term rate of return on plan assets of 8.00%, which was unchanged from the rate assumed as of December 31, 2009. We believe that our actual asset allocation, on average, will approximate the targeted allocation and the estimated return on net assets. We regularly review our actual asset allocation and periodically rebalance plan assets as appropriate.

As of December 31, 2010, the projected benefit obligation was calculated assuming a discount rate of 5.25%, which is a 0.45% decrease from the 5.70% discount rate assumed in 2009. The discount rate was determined by reviewing yields on high-quality bonds that receive one of the two highest ratings given by a recognized rating agency and the expected duration of pension obligations specific to the characteristics of our plan.

Pension cost for 2011, including the benefit restoration plan, is estimated to be $78 million, of which we expect $59 million to impact pre-tax earnings, based on an expected return on plan assets of 8.00% and a discount rate of 5.25% as of December 31, 2010. If the expected return assumption were lowered by 0.50% from 8.00% to 7.50%, 2011 pension cost would increase by approximately $7 million.

As of December 31, 2010, the pension plan projected benefit obligation, including the unfunded benefit restoration plan, exceeded plan assets by $468 million. If the discount rate were lowered by 0.50% from 5.25% to 4.75%, the assumption change would increase our projected benefit obligation and 2011 pension expense by approximately $92 million and $5 million, respectively. In addition, the assumption change would impact our Consolidated Balance Sheet by increasing the regulatory asset recorded as of December 31, 2010 by $75 million and would result in a charge to comprehensive income in 2010 of $11 million, net of tax.

Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plan will impact our future pension expense and liabilities. We cannot predict with certainty what these factors will be.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Impact of Changes in Interest Rates and Energy Commodity Prices

We are exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in our consolidated financial statements. Most of the revenues and income from our business activities are impacted by market risks. Categories of market risk include exposure to commodity prices through non-trading activities, interest rates and equity prices. A description of each market risk is set forth below:

- Commodity price risk results from exposures to changes in spot prices, forward prices and price volatilities of commodities, such as natural gas, natural gas liquids and other energy commodities.

- Interest rate risk primarily results from exposures to changes in the level of borrowings and changes in interest rates.

- Equity price risk results from exposures to changes in prices of individual equity securities.

Management has established comprehensive risk management policies to monitor and manage these market risks. We manage these risk exposures through the implementation of our risk management policies and framework. We manage our commodity price risk exposures through the use of derivative financial instruments and derivative commodity instrument contracts. During the normal course of business, we review our hedging strategies and determine the hedging approach we deem appropriate based upon the circumstances of each situation.

Derivative instruments such as futures, forward contracts, swaps and options derive their value from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments that are listed and traded on an exchange.

Derivative transactions are entered into in our non-trading operations to manage and hedge certain exposures, such as exposure to changes in natural gas prices. We believe that the associated market risk of these instruments can best be understood relative to the underlying assets or risk being hedged.

Interest Rate Risk

As of December 31, 2010, we had outstanding long-term debt, bank loans, lease obligations and obligations under our ZENS that subject us to the risk of loss associated with movements in market interest rates.

We have no material floating rate obligations.

As of December 31, 2009 and 2010, we had outstanding fixed-rate debt (excluding indexed debt securities) aggregating $9.9 billion and $9.1 billion, respectively, in principal amount and having a fair value of $10.4 billion and $9.9 billion, respectively. Because these instruments are fixed-rate, they do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Note 11 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $209 million if interest rates were to decline by 10% from their levels at December 31, 2010. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity.

As discussed in Note 9 to our consolidated financial statements, the ZENS obligation is bifurcated into a debt component and a derivative component. The debt component of $126 million at December 31, 2010 was a fixed-rate obligation and, therefore, did not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by approximately $21 million if interest rates were to decline by 10% from levels at December 31, 2010. Changes in the fair value of the derivative component, a $232 million recorded liability at December 31, 2010, are recorded in our Statements of Consolidated Income and, therefore, we are exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from December 31, 2010 levels, the fair value of the derivative component liability would increase by approximately $5 million, which would be recorded as an unrealized loss in our Statements of Consolidated Income.

Equity Market Value Risk

We are exposed to equity market value risk through our ownership of 7.2 million shares of TW Common, 1.8 million shares of TWC Common and 0.7 million shares of AOL Common, which we hold to facilitate our ability to meet our obligations under the ZENS. Please read Note 9 to our consolidated financial statements for a discussion of our ZENS obligation. A decrease of 10% from the December 31, 2010 aggregate market value of these shares would result in a net loss of approximately $7 million, which would be recorded as an unrealized loss in our Statements of Consolidated Income.

Commodity Price Risk From Non-Trading Activities

We use derivative instruments as economic hedges to offset the commodity price exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in fair value based on a hypothetical 10% movement in energy prices. At December 31, 2010, the recorded fair value of our non-trading energy derivatives was a net liability of $99 million (before collateral). The net liability consisted of a net liability of $123 million associated with price stabilization activities of our Natural Gas Distribution business segment and a net asset of $24 million related to our Competitive Natural Gas Sales and Services business segment. Net assets or liabilities related to the price stabilization activities correspond directly with net over/under recovered gas cost liabilities or assets on the balance sheet. A decrease of 10% in the market prices of energy commodities from their December 31, 2010 levels would have increased the fair value of our non-trading energy derivatives net liability by $2 million. This increase in net liabilities consists of a $12 million increase to net liabilities associated with price stabilization activities of our Natural Gas Distribution business segment and a $10 million decrease to net liabilities related to our Competitive Natural Gas Sales and Services business segment.

The above analysis of the non-trading energy derivatives utilized for commodity price risk management purposes does not include the favorable impact that the same hypothetical price movement would have on our physical purchases and sales of natural gas to which the hedges relate. Furthermore, the non-trading energy derivative portfolio is managed to complement the physical transaction portfolio, reducing overall risks within limits. Therefore, the adverse impact to the fair value of the portfolio of non-trading energy derivatives held for hedging purposes associated with the hypothetical changes in commodity prices referenced above is expected to be substantially offset by a favorable impact on the underlying hedged physical transactions.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related statements of consolidated income, comprehensive income, shareholders’ equity, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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 provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of CenterPoint Energy, Inc. and subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Company and our report dated March 1, 2011 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2011

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL
OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Management has designed its internal control over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with accounting principles generally accepted in the United States of America. Management's assessment included review and testing of both the design effectiveness and operating effectiveness of controls over all relevant assertions related to all significant accounts and disclosures in the financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control — Integrated Framework, our management has concluded that our internal control over financial reporting was effective as of December 31, 2010.

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2010 which is included herein on page 67.

/s/ DAVID M. MCCLANAHAN
President and Chief Executive Officer

/s/ GARY L. WHITLOCK
Executive Vice President and Chief

Financial Officer

March 1, 2011

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31, 2008	2009	2010
	(in millions, except per share amounts)		
Revenues	$ 11,322	$ 8,281	$ 8,785
Expenses:			
Natural gas	7,466	4,371	4,574
Operation and maintenance	1,502	1,664	1,719
Depreciation and amortization	708	743	864
Taxes other than income taxes	373	379	379
Total	10,049	7,157	7,536
Operating Income	1,273	1,124	1,249
Other Income (Expense):			
Gain (loss) on marketable securities	(139)	82	67
Gain (loss) on indexed debt securities	128	(68)	(31)
Interest and other finance charges	(468)	(513)	(481)
Interest on transition and system restoration bonds	(136)	(131)	(140)
Equity in earnings of unconsolidated affiliates	51	15	29
Other, net	14	39	12
Total	(550)	(576)	(544)
Income Before Income Taxes	723	548	705
Income tax expense	(277)	(176)	(263)
Net Income	$ 446	$ 372	$ 442
Basic Earnings Per Share	$ 1.32	$ 1.02	$ 1.08
Diluted Earnings Per Share	$ 1.30	$ 1.01	$ 1.07
Dividends Declared Per Share	$ 0.73	$ 0.76	$ 0.78
Weighted Average Shares Outstanding, Basic	336	365	410
Weighted Average Shares Outstanding, Diluted	344	368	413

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2008	2009	2010
		(in millions)	
Net income	$ 446	$ 372	$ 442
Other comprehensive income (loss):			
Adjustment to pension and other postretirement plans (net of tax of $32, $2 and $5)	(79)	7	6
Net deferred loss from cash flow hedges (net of tax of $2, $-0- and $-0-)	(4)	—	—
Reclassification of deferred loss (gain) from cash flow hedges realized in net income (net of tax of $2, $-0- and $-0-)	(4)	—	1
Other comprehensive income (loss)	(87)	7	7
Comprehensive income	$ 359	$ 379	$ 449

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2010
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents ($151 and $198 related to VIEs at December 31, 2009 and 2010, respectively)	$ 740	$ 199
Investment in marketable securities	300	367
Accounts receivable, net ($44 and $49 related to VIEs at December 31, 2009 and 2010, respectively)	790	835
Accrued unbilled revenues	485	340
Inventory	327	375
Non-trading derivative assets	39	54
Taxes receivable	—	138
Prepaid expense and other current assets ($34 and $39 related to VIEs at December 31, 2009 and 2010, respectively)	223	274
Total current assets	2,904	2,582
Property, Plant and Equipment, net	10,788	11,732
Other Assets:		
Goodwill	1,696	1,696
Regulatory assets ($2,886 and $2,597 related to VIEs at December 31, 2009 and 2010, respectively)	3,677	3,446
Non-trading derivative assets	15	15
Investment in unconsolidated affiliates	463	468
Other	230	172
Total other assets	6,081	5,797
Total Assets	$ 19,773	$ 20,111
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Short-term borrowings	$ 55	$ 53
Current portion of VIE transition and system restoration bonds long-term debt	241	283
Current portion of indexed debt	121	126
Current portion of other long-term debt	541	19
Indexed debt securities derivative	201	232
Accounts payable	648	667
Taxes accrued	148	156
Interest accrued	181	171
Non-trading derivative liabilities	51	68
Accumulated deferred income taxes, net	406	407
Other	445	438

Total current liabilities	3,038	2,620
Other Liabilities:		
Accumulated deferred income taxes, net	2,776	2,934
Unamortized investment tax credits	16	9
Non-trading derivative liabilities	42	16
Benefit obligations	861	906
Regulatory liabilities	921	989
Other	361	438
Total other liabilities	4,977	5,292
Long-term Debt:		
VIE transition and system restoration bonds	2,805	2,522
Other	6,314	6,479
Total long-term debt	9,119	9,001
Commitments and Contingencies (Note 13)		
Shareholders' Equity	2,639	3,198
Total Liabilities and Shareholders' Equity	$ 19,773	$ 20,111

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2008	2009	2010
		(in millions)	
Cash Flows from Operating Activities:			
Net income	$ 446	$ 372	$ 442
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	708	743	864
Amortization of deferred financing costs	29	37	27
Deferred income taxes	487	269	199
Unrealized loss (gain) on marketable securities	139	(82)	(67)
Unrealized loss (gain) on indexed debt securities	(128)	68	31
Write-down of natural gas inventory	30	6	6
Equity in earnings of unconsolidated affiliates, net of distributions	(51)	(3)	13
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(82)	283	101
Inventory	(109)	236	(54)
Taxes receivable	—	—	(138)
Accounts payable	87	(237)	(34)
Fuel cost over (under) recovery	45	(5)	(9)
Non-trading derivatives, net	(25)	28	(5)
Margin deposits, net	(182)	116	7
Interest and taxes accrued	(118)	(41)	(2)
Net regulatory assets and liabilities	(366)	—	14
Other current assets	(27)	27	(2)
Other current liabilities	29	6	(1)
Other assets	(20)	(1)	(8)
Other liabilities	(8)	3	4
Other, net	(33)	16	(2)
Net cash provided by operating activities	851	1,841	1,386
Cash Flows from Investing Activities:			
Capital expenditures	(1,020)	(1,160)	(1,509)
Decrease (increase) in restricted cash of transition and system restoration bond companies	(11)	26	(5)
Decrease (increase) in notes receivable from unconsolidated affiliates	(175)	323	—
Investment in unconsolidated affiliates	(206)	(115)	(18)
Cash received from U.S. Department of Energy grant	—	—	90
Other, net	44	30	22
Net cash used in investing activities	(1,368)	(896)	(1,420)
Cash Flows from Financing Activities:			
Decrease in short-term borrowings, net	(79)	(98)	(2)
Revolving credit facilities, net	1,110	(1,441)	—
Proceeds from commercial paper, net	—	—	183

Proceeds from long-term debt	1,088	1,165	—
Payments of long-term debt	(1,373)	(222)	(783)
Debt issuance costs	(26)	(10)	(2)
Payment of common stock dividends	(246)	(276)	(319)
Proceeds from issuance of common stock, net	80	504	416
Other, net	1	6	—
Net cash provided by (used in) financing activities	555	(372)	(507)
Net Increase (Decrease) in Cash and Cash Equivalents	38	573	(541)
Cash and Cash Equivalents at Beginning of Year	129	167	740
Cash and Cash Equivalents at End of Year	$ 167	$ 740	$ 199
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 586	$ 624	$ 609
Income taxes (refunds), net	(84)	(9)	207
Non-cash transactions:			
Accounts payable related to capital expenditures	96	84	137

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED SHAREHOLDERS' EQUITY

	2008		2009		2010	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions of dollars and shares)					
Preference Stock, none outstanding	—	$ —	—	$ —	—	$ —
Cumulative Preferred Stock, $0.01 par value; authorized 20,000,000 shares, none outstanding	—	—	—	—	—	—
Common Stock, $0.01 par value; authorized 1,000,000,000 shares						
Balance, beginning of year	323	3	346	3	391	4
Issuances related to benefit and investment plans	6	—	7	—	9	—
Issuances related to convertible debt conversions	17	—	—	—	—	—
Issuances related to public offerings	—	—	38	1	25	—
Balance, end of year	346	3	391	4	425	4
Additional Paid-in-Capital						
Balance, beginning of year		3,046		3,158		3,671
Issuances related to benefit and investment plans		112		86		114
Issuances related to public offerings, net of issuance costs		—		427		315
Balance, end of year		3,158		3,671		4,100
Accumulated Deficit						
Balance, beginning of year		(1,194)		(1,008)		(912)
Cumulative effect of change in accounting principle (see Note 6(e))		(15)		—		—
Balance, beginning of year (as adjusted)		(1,209)		(1,008)		(912)
Net income		446		372		442
Common stock dividends — $0.73 per share in 2008, $0.76 per share in 2009 and $0.78 per share in 2010		(245)		(276)		(319)
Balance, end of year		(1,008)		(912)		(789)
Accumulated Other Comprehensive Loss						
Balance, end of year:						
Adjustment to pension and postretirement plans		(127)		(120)		(114)
Net deferred loss from cash flow hedges		(4)		(4)		(3)
Total accumulated other comprehensive loss, end of year		(131)		(124)		(117)
Total Shareholders' Equity		$ 2,022		$ 2,639		$ 3,198

See Notes to Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background

CenterPoint Energy, Inc. (CenterPoint Energy) is a public utility holding company. CenterPoint Energy's operating subsidiaries own and operate electric transmission and distribution facilities, natural gas distribution facilities, interstate pipelines and natural gas gathering, processing and treating facilities. As of December 31, 2010, CenterPoint Energy's indirect wholly owned subsidiaries included:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in the Texas Gulf Coast area that includes the city of Houston; and

- CenterPoint Energy Resources Corp. (CERC Corp. and, together with its subsidiaries, CERC), which owns and operates natural gas distribution systems. Subsidiaries of CERC own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of CERC Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

For a description of CenterPoint Energy's reportable business segments, see Note 16.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(b) Principles of Consolidation

The accounts of CenterPoint Energy and its wholly owned and majority owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. CenterPoint Energy uses the equity method of accounting for investments in entities in which CenterPoint Energy has an ownership interest between 20% and 50% and exercises significant influence. CenterPoint Energy's investments in unconsolidated affiliates include a 50% ownership interest in Southeast Supply Header, LLC (SESH) which owns and operates a 274-mile interstate natural gas pipeline and a 50% interest in Waskom Gas Processing Company (Waskom), a Texas general partnership, which owns and operates a natural gas processing plant and natural gas gathering assets. During 2009, CenterPoint Energy invested $137 million in SESH and received a capital distribution of $23 million from SESH. During 2010, CenterPoint Energy invested $20 million in Waskom. Other investments, excluding marketable securities, are carried at cost.

(c) Revenues

CenterPoint Energy records revenue for electricity delivery and natural gas sales and services under the accrual method and these revenues are recognized upon delivery to customers. Electricity deliveries not billed by month-end are accrued based on daily supply volumes, applicable rates and analyses reflecting significant historical trends and experience. Natural gas sales not billed by month-end are accrued based upon estimated purchased gas volumes, estimated lost and unaccounted for gas and currently effective tariff rates. The Interstate Pipelines and Field Services business segments record revenues as transportation and processing services are provided.

(d) Long-lived Assets and Intangibles

CenterPoint Energy records property, plant and equipment at historical cost. CenterPoint Energy expenses repair and maintenance costs as incurred.

CenterPoint Energy periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets compared to the carrying value of the assets.

(e) Regulatory Assets and Liabilities

CenterPoint Energy applies the guidance for accounting for regulated operations, to the Electric Transmission & Distribution business segment and the Natural Gas Distribution business segment and to portions of the Interstate Pipelines business segment.

CenterPoint Energy's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2009 and 2010, these removal costs of $818 million and $868 million, respectively, are classified as regulatory liabilities in CenterPoint Energy's Consolidated Balance Sheets. A portion of the amount of removal costs that relate to asset retirement obligations has been reclassified from a regulatory liability to an asset retirement liability in accordance with accounting guidance for conditional asset retirement obligations.

(f) Depreciation and Amortization Expense

Depreciation and amortization is computed using the straight-line method based on economic lives or regulatory-mandated recovery periods. Amortization expense includes amortization of regulatory assets and other intangibles.

(g) Capitalization of Interest and Allowance for Funds Used During Construction

Interest and allowance for funds used during construction (AFUDC) are capitalized as a component of projects under construction and are amortized over the assets' estimated useful lives once the assets are placed in service. AFUDC represents the composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction for subsidiaries that apply the guidance for accounting for regulated operations. During 2008, 2009 and 2010, CenterPoint Energy capitalized interest and AFUDC of $12 million, $5 million and $9 million, respectively.

(h) Income Taxes

CenterPoint Energy files a consolidated federal income tax return and follows a policy of comprehensive interperiod tax allocation. CenterPoint Energy uses the asset and liability method of accounting for deferred income taxes. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Investment tax credits that were deferred are being amortized over the estimated lives of the related property. A valuation allowance is established against deferred tax assets for which management believes realization is not considered more likely than not. CenterPoint Energy recognizes interest and penalties as a component of income tax expense.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $24 million and $25 million at December 31, 2009 and 2010, respectively. The provision for doubtful accounts in CenterPoint Energy's Statements of Consolidated Income for 2008, 2009 and 2010 was $54 million, $36 million and $30 million, respectively.

(j) Inventory

Inventory consists principally of materials and supplies and natural gas. Materials and supplies are valued at the lower of average cost or market. Materials and supplies are recorded to inventory when purchased and subsequently charged to expense or capitalized to plant when installed. Natural gas inventories of CenterPoint Energy's Competitive Natural Gas Sales and Services business segment are also primarily valued at the lower of average cost or market. Natural gas inventories of CenterPoint Energy's Natural Gas Distribution business segment are primarily valued at weighted average cost. During both 2009 and 2010, CenterPoint Energy recorded $6 million in write-downs of natural gas inventory to the lower of average cost or market.

	December 31,	
	2009	2010
	(in millions)	
Materials and supplies	$ 138	$ 164
Natural gas	189	211
Total inventory	$ 327	$ 375

(k) Derivative Instruments

CenterPoint Energy is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CenterPoint Energy utilizes derivative instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices and weather on its operating results and cash flows. Such derivatives are recognized in CenterPoint Energy's Consolidated Balance Sheets at their fair value unless CenterPoint Energy elects the normal purchase and sales exemption for qualified physical transactions. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

CenterPoint Energy has a Risk Oversight Committee composed of corporate and business segment officers that oversees all commodity price, weather and credit risk activities, including CenterPoint Energy's marketing, risk management services and hedging activities. The committee's duties are to establish CenterPoint Energy's commodity risk policies, allocate board-approved commercial risk limits, approve the use of new products and commodities, monitor positions and ensure compliance with CenterPoint Energy's risk management policies and procedures and limits established by CenterPoint Energy's board of directors.

CenterPoint Energy's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

(l) Investments in Other Debt and Equity Securities

CenterPoint Energy reports "trading" securities at estimated fair value in its Consolidated Balance Sheets, and any unrealized holding gains and losses are recorded as other income (expense) in its Statements of Consolidated Income.

(m) Environmental Costs

CenterPoint Energy expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. CenterPoint Energy expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. CenterPoint Energy records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(n) Statements of Consolidated Cash Flows

For purposes of reporting cash flows, CenterPoint Energy considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. In connection with the issuance of transition bonds and system restoration bonds, CenterPoint Energy was required to establish restricted cash accounts to collateralize the bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the bonds and are not included in cash and cash equivalents. These restricted cash accounts of $34 million and $39 million at December 31, 2009 and 2010, respectively, are included in other current assets in CenterPoint Energy's Consolidated Balance Sheets. For additional information regarding transition and system restoration bonds, see Notes 5(b) and 5(c). Cash and cash equivalents includes $151 million and $198 million at December 31, 2009 and 2010, respectively, that is held by CenterPoint Energy’s transition and system restoration bond subsidiaries solely to support servicing the transition and system restoration bonds.

(o) New Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board (FASB) issued new accounting guidance on consolidation of variable interest entities (VIEs) that changes how a reporting entity determines a primary beneficiary that would consolidate the VIE from a quantitative risk and rewards approach to a qualitative approach based on which variable interest holder has the power to direct the economic performance related activities of the VIE as well as the obligation to absorb losses or right to receive benefits that could potentially be significant to the VIE. This new guidance requires the primary beneficiary assessment to be performed on an ongoing basis and also requires enhanced disclosures that will provide more transparency about a company’s involvement in a VIE. This new guidance was effective for a reporting entity’s first annual reporting period beginning after November 15, 2009. CenterPoint Energy’s adoption of this new guidance did not have a material impact on its financial position, results of operations or cash flows. As of December 31, 2010, CenterPoint Energy has four VIEs consisting of transition and system restoration bond companies which it consolidates. The consolidated VIEs are wholly-owned bankruptcy remote special purpose entities that were formed specifically for the purpose of securitizing transition and system restoration related property. Creditors of CenterPoint Energy have no recourse to any assets or revenues of the transition and system restoration bond companies. The bonds issued by these VIEs are payable only from and secured by transition and system restoration property and the bond holders have no recourse to the general credit of CenterPoint Energy.

In January 2010, the FASB issued new accounting guidance to require additional fair value related disclosures. It also clarified existing fair value disclosure guidance about the level of disaggregation and about inputs and valuation techniques. This new guidance was effective for the first reporting period beginning after December 15, 2009 except for certain disclosure requirements effective for the first reporting period beginning after December 15, 2010. CenterPoint Energy's adoption of this new guidance did not have a material impact on its financial position, results of operations or cash flows. See Note 8 for the required disclosures. CenterPoint Energy expects that the adoption of certain disclosure requirements effective in 2011 will not have a material impact on its financial position, results of operations or cash flows.

Management believes the impact of other recently issued standards, which are not yet effective, will not have a material impact on CenterPoint Energy’s consolidated financial position, results of operations or cash flows upon adoption.

(3) Property, Plant and Equipment

(a) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2009	2010
		(in millions)	
Electric Transmission & Distribution	27	$ 7,325	$ 7,586
Natural Gas Distribution	31	3,436	3,642
Competitive Natural Gas Sales and Services	26	69	71
Interstate Pipelines	58	2,524	2,594
Field Services	46	931	1,583
Other property	25	485	529
Total		14,770	16,005
Accumulated depreciation and amortization:			
Electric Transmission & Distribution		2,737	2,805
Natural Gas Distribution		825	954
Competitive Natural Gas Sales and Services		13	16
Interstate Pipelines		223	265
Field Services		27	43
Other property		157	190
Total accumulated depreciation and amortization		3,982	4,273
Property, plant and equipment, net		$ 10,788	$ 11,732

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense for 2008, 2009 and 2010 (in millions).

	2008	2009	2010
Depreciation expense	$ 478	$ 496	$ 531
Amortization expense	230	247	333
Total depreciation and amortization expense	$ 708	$ 743	$ 864

(c) Asset Retirement Obligations

A reconciliation of the changes in the asset retirement obligation (ARO) liability is as follows (in millions):

	December 31, 2009	2010
Beginning balance	$ 63	$ 82
Accretion expense	7	5
Revisions in estimates of cash flows	12	(3)
Ending balance	$ 82	$ 84

The increase of $12 million in the ARO from the revision of estimate in 2009 is primarily attributable to the decrease in the credit-adjusted risk-free rate used to value the liability as of the end of the period. The decrease of $3 million in the ARO from the revision of the estimate in 2010 is primarily attributable to changes in the estimated lives of some of the assets underlying the liability. There were no material additions or settlements during the years ended December 31, 2009 and 2010.

(4) Goodwill

Goodwill by reportable segment as of December 31, 2009 and 2010 is as follows (in millions):

Natural Gas Distribution	$746
Interstate Pipelines	579
Competitive Natural Gas Sales and Services	335
Field Services	25
Other Operations	11
Total	$1,696

CenterPoint Energy performs its goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. The impairment evaluation for goodwill is performed by using a two-step process. In the first step, the fair value of each reporting unit is compared with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is generally determined on the basis of discounted cash flows. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference.

CenterPoint Energy performed the test at July 1, 2010, its annual impairment testing date, and determined that no impairment charge for goodwill was required. Other intangibles were not material as of December 31, 2009 and 2010.

(5) Regulatory Matters

(a) Regulatory Assets and Liabilities

The following is a list of regulatory assets/liabilities reflected on CenterPoint Energy's Consolidated Balance Sheets as of December 31, 2009 and 2010:

	December 31,	
	2009	2010
	(in millions)	
Securitized regulatory assets	$ 2,886	$ 2,597
Unrecognized equity return	(232)	(216)
Unamortized loss on reacquired debt	67	61
Pension and postretirement-related regulatory asset (1)	813	838
Other long-term regulatory assets	143	166
Total regulatory assets (1)	3,677	3,446
Estimated removal costs	818	868
Other long-term regulatory liabilities	103	121
Total regulatory liabilities	921	989
Total regulatory assets and liabilities, net	$ 2,756	$ 2,457

(1) CenterPoint Houston's actuarially determined pension expense for 2009 and 2010 in excess of the 2007 base year amount is being deferred for rate making purposes and is being addressed in its current rate application pursuant to Texas law. CenterPoint Houston deferred as a regulatory asset $32 million and $26 million in pension and other postemployment expenses during the years ended December 31, 2009 and 2010, respectively. Deferred pension expense of $32 million and $58 million at December 31, 2009 and 2010, respectively, is not earning a return. Other regulatory assets that are not earning a return were not material at December 31, 2009 and 2010.

(b) Recovery of True-Up Balance

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas Electric Choice Plan (Texas electric restructuring law). In December 2004, the Texas Utility Commission issued its final order (True-Up Order) allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and provided for adjustment of the amount to be recovered to include interest on the balance until recovery, along with the principal portion of additional excess mitigation credits (EMCs) returned to customers after August 31, 2004 and certain other adjustments.

CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, that court issued its judgment on the various appeals. In its judgment, the district court:

- reversed the Texas Utility Commission's ruling that had denied CenterPoint Houston recovery of a portion of the capacity auction true-up amounts;

- reversed the Texas Utility Commission's ruling that precluded CenterPoint Houston from recovering the interest component of the EMCs paid to retail electric providers (REPs); and

- affirmed the True-Up Order in all other respects.

The district court's decision would have had the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston's initial request.

CenterPoint Houston and other parties appealed the district court's judgment to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court's judgment to the extent it restored the capacity auction true-up amounts;

- reversed the district court's judgment to the extent it upheld the Texas Utility Commission's decision to allow CenterPoint Houston to recover EMCs paid to its former affiliate Reliant Energy, Inc. (Reliant Energy, Inc., formerly known as Reliant Resources, Inc., changed its name in 2009 to "RRI Energy, Inc." in connection with the sale of its Texas retail electric business, and again in December 2010 to "GenOn Energy, Inc." in connection with the merger of one of its wholly owned subsidiaries with Mirant Corporation. For convenience, we refer to this company as "RRI" in the context of discussing transactions relating to our formation, our pending true-up appeal and other historical matters, and as "GenOn" in the present and future context, unless stated otherwise.);

- ordered that the tax normalization issue described below be remanded to the Texas Utility Commission as requested by the Texas Utility Commission; and

- affirmed the district court's judgment in all other respects.

In April 2008, the court of appeals denied all motions for rehearing and reissued substantially the same opinion as it had rendered in December 2007.

In June 2008, CenterPoint Houston petitioned the Texas Supreme Court for review of the court of appeals decision. In its petition, CenterPoint Houston seeks reversal of the parts of the court of appeals decision that (i) denied recovery of EMCs paid to RRI, (ii) denied recovery of the capacity auction true-up amounts allowed by the district court, (iii) affirmed the Texas Utility Commission's rulings that denied recovery of approximately $378 million related to depreciation and (iv) affirmed the Texas Utility Commission's refusal to permit CenterPoint Houston to utilize the partial stock valuation methodology for determining the market value of its former generation assets. Two other petitions for review were filed with the Texas Supreme Court by other parties to the appeal. In those petitions parties contend that (i) the Texas Utility Commission was without authority to fashion the methodology it used for valuing the former generation assets after it had determined that CenterPoint Houston could not use the partial stock valuation method, (ii) in fashioning the method it used for valuing the former generating assets, the Texas Utility Commission deprived parties of their due process rights and an opportunity to be heard, (iii) the net book value of the generating assets should have been adjusted downward due to the impact of a purchase option that had been granted to RRI, (iv) CenterPoint Houston should not have been permitted to recover construction work in progress balances without proving those amounts in the manner required by law and (v) the Texas Utility Commission was without authority to award interest on the capacity auction true-up award.

In June 2009, the Texas Supreme Court granted the petitions for review of the court of appeals decision. Oral argument before the court was held in October 2009. Although CenterPoint Energy and CenterPoint Houston believe that CenterPoint Houston's true-up request is consistent with applicable statutes and regulations and, accordingly, that it is reasonably possible that it will be successful in its appeal to the Texas Supreme Court, CenterPoint Energy can provide no assurance as to the ultimate court rulings on the issues to be considered in the appeal or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue described below.

To reflect the impact of the True-Up Order, in 2004 and 2005, CenterPoint Energy recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in CenterPoint Energy's consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of further review by the Texas Supreme Court, CenterPoint Energy anticipates that it would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue described below, but could range from $190 million to $440 million (pre-tax) plus interest subsequent to December 31, 2010.

In the True-Up Order, the Texas Utility Commission reduced CenterPoint Houston's stranded cost recovery by approximately $146 million, which was included in the extraordinary loss discussed above, to reflect the present value of certain deferred tax benefits associated with its former electric generation assets. CenterPoint Energy believes that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 that would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, the IRS subsequently withdrew those proposed normalization regulations and, in March 2008, adopted final regulations that would not permit utilities like CenterPoint Houston to pass the tax benefits back to customers without creating normalization violations. In addition, CenterPoint Energy received a Private Letter Ruling (PLR) from the IRS in August 2007, prior to adoption of the final regulations, that confirmed that the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations with respect to the ADITC and EDFIT.

If the Texas Utility Commission's order relating to the ADITC reduction is not reversed or otherwise modified on remand so as to eliminate the normalization violation, the IRS could require CenterPoint Energy to pay an amount equal to CenterPoint Houston's unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. Such treatment, if required by the IRS, could have a material adverse impact on CenterPoint Energy's results of operations, financial condition and cash flows in addition to any potential loss resulting from final resolution of the True-Up Order. Following the adoption by the IRS of the final regulations described above, the Texas Utility Commission requested, and the court of appeals ordered, that this issue be remanded to that commission for further consideration. No party has challenged that order by the court of appeals although the Texas Supreme Court has the authority to consider all aspects of the rulings above, not just those challenged specifically by the appellants. CenterPoint Energy and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate and administrative process. Although the Texas Utility Commission has requested that this issue be remanded to it by the courts and has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation, no prediction can be made as to the ultimate action the Texas Utility Commission may take on this issue on remand.

The Texas electric restructuring law allowed the amounts awarded to CenterPoint Houston in the Texas Utility Commission's True-Up Order to be recovered either through securitization or through implementation of a competition transition charge (CTC) or both. Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed by a Travis County district court, in December 2005, a new special purpose subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84% to 5.30% and final maturity dates ranging from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

In July 2005, CenterPoint Houston received an order from the Texas Utility Commission allowing it to implement a CTC designed to collect the remaining $596 million from the True-Up Order over 14 years plus interest at an annual rate of 11.075% (CTC Order). The CTC Order authorized CenterPoint Houston to impose a charge on REPs to recover the portion of the true-up balance not recovered through a financing order. The CTC Order also allowed CenterPoint Houston to collect approximately $24 million of rate case expenses over three years without a return through a separate tariff rider (Rider RCE). CenterPoint Houston implemented the CTC and Rider RCE effective September 13, 2005 and began recovering approximately $620 million. The return on the CTC portion of the true-up balance was included in CenterPoint Houston's tariff-based revenues beginning September 13, 2005. Effective August 1, 2006, the interest rate on the unrecovered balance of the CTC was reduced from 11.075% to 8.06% pursuant to a revised rule adopted by the Texas Utility Commission in June 2006. Recovery of rate case expenses under Rider RCE was completed in September 2008.

Certain parties appealed the CTC Order to a district court in Travis County. In May 2006, the district court issued a judgment reversing the CTC Order in three respects. First, the court ruled that the Texas Utility Commission had improperly relied on provisions of its rule dealing with the interest rate applicable to CTC amounts. The district court reached that conclusion based on its belief that the Texas Supreme Court had previously invalidated that entire section of the rule. The 11.075% interest rate in question was applicable from the implementation of the CTC Order on September 13, 2005 until August 1, 2006, the effective date of the implementation of a new CTC in compliance with the revised rule discussed above. Second, the district court reversed the Texas Utility Commission's ruling that allows CenterPoint Houston to recover through Rider RCE the costs (approximately $5 million) for a panel appointed by the Texas Utility Commission in connection with the valuation of electric generation assets. Finally, the district court accepted the contention of one party that the CTC should not be allocated to retail customers that have switched to new on-site generation. The Texas Utility Commission and CenterPoint Houston appealed the district court's judgment to the Texas Third Court of Appeals, and in July 2008, the court of appeals reversed the district court's judgment in all respects and affirmed the Texas Utility Commission's order. Two parties appealed the court of appeals decision to the Texas Supreme Court and on October 22, 2010, the Texas Supreme Court issued an opinion affirming the judgment of the court of appeals. The Texas Supreme Court's decision did not have an impact on CenterPoint Energy's or CenterPoint Houston's financial position, results of operations or cash flows.

During the 2007 legislative session, the Texas legislature amended statutes prescribing the types of true-up balances that can be securitized by utilities and authorized the issuance of transition bonds to recover the balance of the CTC. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of the remaining balance of the CTC, adjusted to refund certain unspent environmental retrofit costs and to recover the amount of the final fuel reconciliation settlement. CenterPoint Houston reached substantial agreement with other parties to this proceeding, and a financing order was approved by the Texas Utility Commission in September 2007. In February 2008, pursuant to the financing order, a new special purpose subsidiary of CenterPoint Houston issued approximately $488 million of transition bonds in two tranches with interest rates of 4.192% and 5.234% and final maturity dates of February 2020 and February 2023, respectively. Contemporaneously with the issuance of those bonds, the CTC was terminated and a transition charge was implemented. During the year ended December 31, 2008, CenterPoint Houston recognized approximately $5 million in operating income from the CTC.

As of December 31, 2010, CenterPoint Energy has not recognized an allowed equity return of $178 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates. During the years ended December 31, 2008, 2009 and 2010, CenterPoint Houston recognized approximately $13 million, $13 million and $15 million, respectively, of the allowed equity return.

(c) Hurricane Ike

CenterPoint Houston’s electric delivery system suffered substantial damage as a result of Hurricane Ike, which struck the upper Texas coast in September 2008. CenterPoint Houston deferred the system restoration costs as management believed it was probable that such costs would be recovered through the regulatory process. As a result, system restoration costs did not affect CenterPoint Energy’s or CenterPoint Houston’s reported operating income for 2008 or 2009.

CenterPoint Houston filed with the Texas Utility Commission an application for review and approval for recovery of approximately $678 million, including approximately $608 million in system restoration costs identified as of the end of February 2009, plus $2 million in regulatory expenses, $13 million in certain debt issuance costs and $55 million in incurred and projected carrying costs calculated through August 2009. In July 2009, CenterPoint Houston reached a settlement agreement with the parties to the proceeding. Under that settlement agreement, CenterPoint Houston was entitled to recover a total of $663 million in costs relating to Hurricane Ike, along with carrying costs from September 1, 2009 until system restoration bonds were issued. The Texas Utility Commission issued an order in August 2009 approving the settlement agreement and authorizing recovery of $663 million, of which $643 million was attributable to distribution service and eligible for securitization and the remaining $20 million was attributable to transmission service and eligible for recovery through the existing mechanisms established to recover transmission costs.

In August 2009, the Texas Utility Commission issued a financing order allowing CenterPoint Houston to securitize $643 million in distribution service costs plus carrying charges from September 1, 2009 through the date the system restoration bonds were issued, as well as certain up-front qualified costs capped at approximately $6 million. In November 2009, CenterPoint Houston issued approximately $665 million of system restoration bonds through its CenterPoint Energy Restoration Bond Company, LLC subsidiary with interest rates of 1.833% to 4.243% and final maturity dates ranging from February 2016 to August 2023. The bonds will be repaid over time through a charge imposed on customers.

In accordance with the financing order, CenterPoint Houston also placed a separate customer credit in effect when the storm restoration bonds were issued. That credit (ADFIT Credit) is applied to customers’ bills while the bonds are outstanding to reflect the benefit of accumulated deferred federal income taxes (ADFIT) associated with the storm restoration costs (including a carrying charge of 11.075%). The beginning balance of the ADFIT related to storm restoration costs was approximately $207 million and will decline over the life of the system restoration bonds as taxes are paid on the system restoration tariffs. The ADFIT Credit reduced operating income in 2010 by approximately $23 million.

In accordance with the orders discussed above, as of December 31, 2010, CenterPoint Houston has recorded $604 million associated with distribution-related storm restoration costs as a securitized regulatory asset. During the year ended December 31, 2009, CenterPoint Houston recognized a return of borrowing costs of $23 million that is included in other income in CenterPoint Energy’s Statements of Consolidated Income.

As of December 31, 2010, CenterPoint Energy has not recognized an allowed equity return of $38 million on CenterPoint Houston’s allowed system restoration costs because such return will be recognized as it is recovered in rates. During the years ended December 31, 2009 and 2010, CenterPoint Houston recognized less than $1 million and $1 million, respectively, of the allowed equity return.

(d) Rate Proceedings

Texas - June 2010 Rate Proceeding. As required under the final order in its 2006 rate proceeding, in June 2010 CenterPoint Houston filed an application to change rates with the Texas Utility Commission and the cities in its service area, including cost data and other information supporting an annual increase of $106 million for delivery charges to the REPs that sell electricity to end-use customers in CenterPoint Houston's service territory that was offset by a reduction of other utility revenues, resulting in a $92 million requested annual revenue increase. The rate filing package also supported an annual increase of $18 million for wholesale transmission customers.

In the filing, CenterPoint Houston also requested reconciliation of its AMS costs incurred as of March 31, 2010, and revision of the estimated costs to complete the AMS project in order to reflect $150 million in funds from the $200 million DOE stimulus grant awarded to CenterPoint Houston and updated cost information. The reconciliation plan also requested that the duration of the residential AMS surcharge be shortened by six years from the original 12-year plan.

In its rate filing, CenterPoint Houston sought a return on equity of 11.25% and proposed that rates be based on a capital structure of 50% equity and 50% long-term debt.

Hearings concerning the rate filing concluded in October 2010, and a Proposal for Decision was issued by the presiding Administrative Law Judges. On February 3, 2011 the Texas Utility Commission voted on the various contested issues presented by the rate filing. The Texas Utility Commission has not yet issued a formal order implementing its decisions, and the order, once issued, will be subject to revision based on motions for rehearing by the parties to the proceeding and could be appealed to the Texas courts.

Based on the public deliberations and votes by the Commissioners, CenterPoint Houston anticipates that the order of the Texas Utility Commission will provide for a base rate increase for CenterPoint Houston of approximately $14.7 million per year for delivery charges to the REPs and a decrease to charges to wholesale transmission customers of $12.3 million per year. Further, the order is expected to provide a mechanism to track amounts for uncertain tax positions and provide for ultimate recovery of those costs.

The order is expected to be based on an authorized return on equity for CenterPoint Houston of 10%, a cost of debt of –6.74–%, a capital structure comprised of 55% debt and 45% common equity, and an overall rate of return of 8.21%. The decision also will implement CenterPoint Houston's request to reconcile costs incurred for the AMS project and to shorten the period for collecting the AMS surcharge from twelve to six years for residential customers in order to reflect the funds received from the DOE.

Based on CenterPoint Houston's understanding of the Texas Utility Commission's votes, CenterPoint Houston anticipates that annual operating income will be reduced by approximately $30 million from 2010 levels as a result of the Texas Utility Commission's decision. CenterPoint Houston expects that revised rates based on the Texas Utility Commission's decision will be implemented during the second quarter of 2011.

Texas - Other. In May 2009, CenterPoint Houston filed an application at the Texas Utility Commission seeking approval of certain estimated 2010 energy efficiency program costs, an energy efficiency performance bonus for 2008 programs, and carrying costs totaling approximately $10 million. The application sought to begin recovery of these costs through a surcharge effective July 1, 2010. In October 2009, the Texas Utility Commission issued its order approving recovery of the 2010 energy efficiency program costs and a partial performance bonus of approximately $8 million, plus carrying costs, but disallowed a recovery of a performance bonus of $2 million on approximately $10 million in 2008 energy efficiency costs expended pursuant to the terms of a settlement agreement in a prior rate case. CenterPoint Houston began collecting the approved amounts in July 2010. CenterPoint Houston appealed the denial of the full 2008 performance bonus to the 98th district court in Travis County, Texas. In October 2010, the district court upheld the Texas Utility Commission's decision. In February 2011, CenterPoint Houston appealed the district court's judgment to the Texas 3rd Court of Appeals at Austin, Texas, where the case remains pending.

In April 2010, CenterPoint Houston filed an application with the Texas Utility Commission seeking approval of certain estimated 2011 energy efficiency programs, an energy efficiency performance bonus for 2009 programs, and recovery of revenue losses related to the implementation of the 2009 energy efficiency program totaling approximately $14.4 million. The application sought to begin recovery of these costs through a surcharge beginning in January 2011. In November 2010, the Texas Utility Commission issued its order approving recovery of the 2011 energy efficiency program costs and a partial performance bonus of approximately $11 million, but disallowed a recovery of a performance bonus of $2 million on the 2009 energy efficiency costs expended pursuant to the terms of the settlement agreement referenced above. The Texas Utility Commission further concluded that it does not have statutory authority to permit recovery of the approximately $1.4 million in lost revenue associated with 2009 energy efficiency programs. CenterPoint Houston began collecting the approved amounts in January 2011, but has appealed the denial of the full 2009 performance bonus and lost revenue to the 201st district court in Travis County, Texas, where the case remains pending.

In March 2008, the natural gas distribution business of CERC (Gas Operations) filed a request to change its rates with the Railroad Commission of Texas (Railroad Commission) and the 47 cities in its Texas Coast service territory, an area consisting of approximately 230,000 customers in cities and communities on the outskirts of Houston. In 2008, the Railroad Commission approved the implementation of rates increasing annual revenues by approximately $3.5 million. The approved rates were contested by a coalition of nine cities in an appeal to the 353rd district court in Travis County, Texas. In January 2010, that court reversed the Railroad Commission's order in part and remanded the matter to the Railroad Commission. In its final judgment, the court ruled that the Railroad Commission lacked authority to impose the approved cost of service adjustment mechanism in both those nine cities and in those areas in which the Railroad Commission has original jurisdiction. The Railroad Commission and Gas Operations have appealed the court's ruling on the cost of service adjustment mechanism to the 3rd Court of Appeals at Austin, Texas. Oral arguments were held in February 2011. CenterPoint Energy does not expect the outcome of this matter to have a material adverse impact on its financial condition, results of operations or cash flows. The cost of service adjustment was initially effective for three successive years ending in calendar year 2010, but would automatically renew for successive three-year periods unless Gas Operations or the regulatory authority having original jurisdiction gave written notice to discontinue the adjustment mechanism by February 1, 2011. Certain cities that agreed to the initial implementation notified Gas Operations by February 1, 2011 of their desire to discontinue the adjustment mechanism. Gas Operations will continue the cost of service adjustments for the remaining areas.

In July 2009, Gas Operations filed a request to change its rates with the Railroad Commission and the 29 cities in its Houston service territory, consisting of approximately 940,000 customers in and around Houston. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Houston service territory. As finally submitted to the Railroad Commission and the cities, the proposed new rates would have resulted in an overall increase in annual revenue of $20.4 million, excluding carrying costs of approximately $2 million on its gas inventory, and would be subject to an annual cost of service adjustment. In January 2010, Gas Operations withdrew its request for an annual cost of service adjustment mechanism due to the uncertainty caused by the court's ruling in the above-mentioned Texas Coast appeal. In February 2010, the Railroad Commission issued its decision authorizing a revenue increase of $5.1 million annually, reflecting reduced depreciation rates as well as adjustments to pension and other employee benefits, accumulated deferred income taxes and other items. The Railroad Commission also approved a surcharge of $0.9 million per year to recover Hurricane Ike costs over three years. These rates went into effect in March 2010. Gas Operations and other parties are seeking judicial review of the Railroad Commission's decision in the 261st District Court in Travis County, Texas.

In December 2010, Gas Operations filed a request to change its rates with the Railroad Commission and the 66 cities in its South Texas service territory, consisting of approximately 137,000 customers. The request seeks an increase in base revenues of approximately $6.5 million, based on an 11% return on equity and a capital structure of 56% equity and 44% debt. A decision from the Railroad Commission is anticipated in the summer of 2011.

Rulemaking Proceedings. In January 2010, the Texas Utility Commission published proposed amendments to its energy efficiency rule. During the statutory comment period, CenterPoint Houston urged the adoption of a lost revenue recovery mechanism as part of the rule amendments to keep whole the utilities participating in the required energy efficiency programs. In July 2010, the Texas Utility Commission adopted amendments to its energy efficiency program rules, but concluded it did not have the statutory authority to permit recovery of lost revenue associated with energy efficiency programs. CenterPoint Houston has appealed the rule to the Texas 3rd Court of Appeals at Austin, Texas on the basis it is invalid as amended because it does not permit lost revenue recovery.

In October 2010, amended rules of the Texas Utility Commission relating to the Transmission Cost Recovery Factor (TCRF) became effective. The amended rules permit a distribution service provider (DSP) such as CenterPoint Houston to defer for future recovery increases in transmission costs that are charged to the DSP by transmission service providers (TSPs) during the interim period before the DSP is authorized to request an adjustment to its TCRF. The TCRF permits a DSP to recover from REPs approved changes in transmission charges from TSPs, but the TCRF can be changed by the DSP only twice per year on application to the Texas Utility Commission. The revised rules permit DSPs to obtain full recovery of the increased transmission charges.

Minnesota. In November 2008, Gas Operations filed a request with the Minnesota Public Utilities Commission (MPUC) to increase its rates for utility distribution service by $59.8 million annually. In addition, Gas Operations sought an adjustment mechanism that would annually adjust rates to reflect changes in use per customer. In December 2008, the MPUC accepted the case and approved an interim rate increase of $51.2 million, which became effective on January 2, 2009, subject to refund. In January 2010, the MPUC issued its decision authorizing a revenue increase of $40.8 million per year, with an overall rate of return of 8.09% (10.24% return on equity). The MPUC also authorized Gas Operations to implement a pilot program for residential and small volume commercial customers that is intended to decouple gas revenues from customers' natural gas usage. In July 2010, Gas Operations implemented the revised rates approved by the MPUC and in August 2010 completed the refund to customers of the difference between the amounts finally approved by the MPUC and interim amounts collected. In October 2010, the MPUC approved a request by Gas Operations to implement a rate adjustment to increase its conservation improvement plan (CIP) recovery rate from $9.7 million to $23.2 million annually. In addition, the MPUC approved a $1.4 million incentive based on Gas Operations' 2009 CIP program.

(e) Renewal of Affiliate Pipeline Transportation and Storage Service Agreements

In April 2010, Gas Operations and CenterPoint Energy Gas Transmission Company, LLC (CEGT) began negotiations to renew the pipeline transportation and storage service agreements that were scheduled to expire on March 31, 2012 for Arkansas, Louisiana, Oklahoma and Texas. In May 2010, Gas Operations and CEGT reached agreement to renew the contracts for terms extending through March 31, 2021. All applicable regulatory approvals have been received.

(f) Regulatory Accounting

CenterPoint Energy has a 50% ownership interest in SESH, which owns and operates a 274-mile interstate natural gas pipeline. In 2009, SESH discontinued the use of guidance for accounting for regulated operations, which resulted in CenterPoint Energy recording its share of the effects of such write-offs of SESH's regulatory assets through non-cash pre-tax charges for the year ended December 31, 2009 of $16 million. These non-cash charges are reflected in equity in earnings of unconsolidated affiliates in the Statements of Consolidated Income. The related tax benefits of $6 million are reflected in the Income Tax Expense line in the Statements of Consolidated Income.

(6) Stock-Based Incentive Compensation Plans and Employee Benefit Plans

(a) Stock-Based Incentive Compensation Plans

CenterPoint Energy has long-term incentive plans (LTIPs) that provide for the issuance of stock-based incentives, including stock options, performance awards, restricted stock unit awards and restricted and unrestricted stock awards to officers and key employees. Approximately 12 million shares of CenterPoint Energy common stock are authorized under these plans for the issuance of new grants.

Equity awards are granted to employees without cost to the participants. The performance awards granted in 2008, 2009 and 2010 are distributed based upon the achievement of certain objectives over a three-year performance cycle. The stock awards granted in 2008, 2009 and 2010 are subject to the operational condition that total common dividends declared during the three-year vesting period must be at least $2.19, $2.28 and $2.34 per share, respectively. The stock awards generally vest at the end of a three-year period. Upon vesting, both the performance and stock awards are issued to the participants along with the value of dividend equivalents earned over the performance cycle or vesting period. CenterPoint Energy issues new shares in order to satisfy share-based payments related to LTIPs.

CenterPoint Energy recorded LTIPs compensation expense of $10 million, $15 million and $17 million for the years ended December 31, 2008, 2009 and 2010, respectively. This expense is included in Operation and Maintenance

Expense in the Statements of Consolidated Income.

The total income tax benefit recognized related to LTIPs was $4 million, $6 million and $6 million in the years ended December 31, 2008, 2009 and 2010, respectively. No compensation cost related to LTIPs was capitalized as a part of inventory or fixed assets in 2008, 2009 or 2010. The actual tax benefit realized for tax deductions related to LTIPs totaled $5 million, $6 million and $5 million, for 2008, 2009 and 2010, respectively.

Compensation costs for the performance and stock awards granted under LTIPs are measured using fair value and expected achievement levels on the grant date. The fair value of awards granted to employees after April 2009 are based on the closing stock price of CenterPoint Energy's common stock on the grant date. The fair value of awards granted prior to May 2009 were based on the average of the high and low stock price of CenterPoint Energy's common stock on the grant date. The compensation expense is recorded on a straight-line basis over the vesting period. Forfeitures are estimated on the date of grant based on historical averages. For performance awards with operational goals, the expected achievement levels are revised as goal achievements are evaluated.

The following tables summarize CenterPoint Energy's LTIPs activity for 2010:

Stock Options

	Outstanding Options Year Ended December 31, 2010			
	Shares (Thousands)	Weighted-Average Exercise Price	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2009	4,513	$ 17.95		
Expired	(399)	17.25		
Cancelled	(207)	31.48		
Exercised	(830)	10.05		
Outstanding at December 31, 2010	3,077	19.27	1.3	$ 12
Exercisable at December 31, 2010	3,077	19.27	1.3	12

Cash received from stock options exercised was $3 million, $4 million and $9 million for 2008, 2009 and 2010, respectively.

CenterPoint Energy has not issued stock options since 2004.

Performance Awards

	Outstanding and Non-Vested Shares Year Ended December 31, 2010			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2009	2,583	$ 14.62		
Granted	1,130	14.21		
Forfeited or cancelled	(350)	17.24		
Vested and released to participants	(295)	18.09		
Outstanding at December 31, 2010	3,068	13.84	1.1	$ 37

The outstanding and non-vested shares displayed in the table above assumes that shares are issued at the maximum performance level. The aggregate intrinsic value reflects the impacts of current expectations of achievement and stock price.

Stock Awards

	Outstanding and Non-Vested Stock Shares Year Ended December 31, 2010			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2009	951	$ 14.36		
Granted	440	14.26		
Forfeited or cancelled	(25)	13.38		
Vested and released to participants	(270)	16.65		
Outstanding at December 31, 2010	1,096	13.78	1.2	$ 17

The weighted-average grant-date fair values of awards granted were as follows for 2008, 2009 and 2010:

	Year Ended December 31,		
	2008	2009	2010
Performance awards	$ 15.40	$ 12.42	$ 14.21
Stock awards	15.09	12.30	14.26

Valuation Data

The total intrinsic value of awards received by participants was as follows for 2008, 2009 and 2010:

	Year Ended December 31,		
	2008	2009	2010
		(in millions)	
Stock options exercised	$ 2	$ 2	$ 4
Performance awards	6	7	5
Stock awards	5	4	4

The total grant date fair value of performance and stock awards which vested during the years ended December 31, 2008, 2009 and 2010 was $8 million, $11 million and $10 million, respectively. As of December 31, 2010, there was $31 million of total unrecognized compensation cost related to non-vested performance and stock awards which is expected to be recognized over a weighted-average period of 1.7 years.

(b) Pension and Postretirement Benefits

CenterPoint Energy maintains a non-contributory qualified defined benefit pension plan covering substantially all employees, with benefits determined using a cash balance formula. Under the cash balance formula, participants accumulate a retirement benefit based upon 5% of eligible earnings, which increased from 4% effective January 1, 2009, and accrued interest. Participants are 100% vested in their benefit after completing three years of service. In addition to the non-contributory qualified defined benefit pension plan, CenterPoint Energy maintains unfunded non-qualified benefit restoration plans which allow participants to receive the benefits to which they would have been entitled under CenterPoint Energy's non-contributory pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated.

CenterPoint Energy provides certain healthcare and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Under plan amendments, effective in early 1999, healthcare benefits for future retirees were changed to limit employer contributions for medical coverage.

Such benefit costs are accrued over the active service period of employees. The net unrecognized transition obligation is being amortized over approximately 20 years.

CenterPoint Energy's net periodic cost includes the following components relating to pension, including the benefit restoration plan, and postretirement benefits:

	Year Ended December 31,					
	2008		2009		2010	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)					
Service cost	$ 31	$ 1	$ 25	$ 1	$ 31	$ 1
Interest cost	101	27	113	28	102	25
Expected return on plan assets	(147)	(12)	(98)	(9)	(109)	(10)
Amortization of prior service cost (credit)	(8)	3	3	3	3	3
Amortization of net loss	23	—	68	—	59	—
Amortization of transition obligation	—	7	—	7	—	7
Benefit enhancement	1	—	—	—	—	—
Net periodic cost	$ 1	26	111	30	86	26

CenterPoint Energy used the following assumptions to determine net periodic cost relating to pension and postretirement benefits:

	December 31,					
	2008		2009		2010	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Discount rate	6.40 %	6.40 %	6.90 %	6.90 %	5.70 %	5.70 %
Expected return on plan assets	8.50	7.60	8.00	7.05	8.00	7.05
Rate of increase in compensation levels	4.60	—	4.60	—	4.60	—

In determining net periodic benefits cost, CenterPoint Energy uses fair value, as of the beginning of the year, as its basis for determining expected return on plan assets.

The following table summarizes changes in the benefit obligation, plan assets, the amounts recognized in consolidated balance sheets and the key assumptions of CenterPoint Energy's pension, including benefit restoration, and postretirement plans. The measurement dates for plan assets and obligations were December 31, 2009 and 2010.

	December 31,			
	2009		2010	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions, except for actuarial assumptions)			
Change in Benefit Obligation				
Benefit obligation, beginning of year	$ 1,710	$ 426	$ 1,866	$ 450
Service cost	25	1	31	1
Interest cost	113	28	102	25
Participant contributions	—	6	—	7
Benefits paid	(111)	(42)	(115)	(50)
Actuarial gain	129	29	85	24
Medicare reimbursement	—	2	—	3
Benefit obligation, end of year	1,866	450	1,969	460
Change in Plan Assets				
Fair value of plan assets, beginning of year	1,276	135	1,432	146
Employer contributions	20	28	8	29
Participant contributions	—	6	—	7
Benefits paid	(111)	(42)	(115)	(50)
Actual investment return	247	19	176	12
Fair value of plan assets, end of year	1,432	146	1,501	144
Funded status, end of year	$ (434)	$ (304)	$ (468)	$ (316)
Amounts Recognized in Balance Sheets				
Current liabilities-other	$ (9)	$ (9)	$ (9)	$ (9)
Other liabilities-benefit obligations	(425)	(295)	(459)	(307)
Net liability, end of year	$ (434)	$ (304)	$ (468)	$ (316)
Actuarial Assumptions				
Discount rate	5.70 %	5.70 %	5.25 %	5.20 %
Expected return on plan assets	8.00	7.05	8.00	7.05
Rate of increase in compensation levels	4.60	—	4.60	—
Healthcare cost trend rate assumed for the next year	—	7.50	—	8.50
Prescription drug cost trend rate assumed for the next year	—	8.00	—	8.50
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	—	5.50	—	5.50
Year that the healthcare rate reaches the ultimate trend rate	—	2014	—	2017
Year that the prescription drug rate reaches the ultimate trend rate	—	2015	—	2017

The accumulated benefit obligation for all defined benefit pension plans was $1,864 million and $1,954 million as of December 31, 2009 and 2010, respectively.

The expected rate of return assumption was developed by a weighted-average return analysis of the targeted asset allocation of CenterPoint Energy's plans and the expected real return for each asset class, based on the long-term capital market assumptions, adjusted for investment fees and diversification effects, in addition to expected inflation.

The discount rate assumption was determined by matching the accrued cash flows of CenterPoint Energy's plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to thirty years.

For measurement purposes, healthcare and prescription costs are assumed to increase 8.50% during 2011, after which this rate decreases until reaching the ultimate trend rate of 5.50% in 2017, except for the 2013 rate which is expected to increase to 9.00% in anticipation of the healthcare exchanges being introduced to the market in 2014.

Amounts recognized in accumulated other comprehensive loss consist of the following:

	December 31,			
	2009		2010	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)			
Unrecognized actuarial loss	$ 162	$ 15	$ 151	$ 18
Unrecognized prior service cost	16	9	15	7
Unrecognized transition obligation	—	3	—	2
Net amount recognized in accumulated other comprehensive loss	$ 178	$ 27	$ 166	$ 27

The changes in plan assets and benefit obligations recognized in other comprehensive income during 2010 are as follows (in millions):

	Pension Benefits	Postretirement Benefits
Net loss (gain)	$ (24)	$ 3
Amortization of net loss	13	—
Prior service credit	(2)	(4)
Amortization of prior service credit	1	2
Transition obligation	—	(1)
Total recognized in comprehensive income	$ (12)	$ —

The total expense recognized in net periodic costs and other comprehensive income was $74 million and $26 million for pension and postretirement benefits, respectively, for the year ended December 31, 2010.

The amounts in accumulated other comprehensive loss expected to be recognized as components of net periodic benefit cost during 2011 are as follows (in millions):

	Pension Benefits	Postretirement Benefits
Unrecognized actuarial loss	$ 12	$ —
Unrecognized prior service cost	1	2
Amounts in accumulated comprehensive income to be recognized in net periodic cost in 2011	$ 13	$ 2

The following table displays pension benefits related to CenterPoint Energy's pension plans that have accumulated benefit obligations in excess of plan assets:

	December 31,			
	2009		2010	
	Pension Qualified	Pension Non-qualified	Pension Qualified	Pension Non-qualified
	(in millions)			
Accumulated benefit obligation	$ 1,770	$ 94	$ 1,860	$ 94
Projected benefit obligation	1,772	94	1,875	94
Fair value of plan assets	1,432	—	1,501	—

Assumed healthcare cost trend rates have a significant effect on the reported amounts for CenterPoint Energy's postretirement benefit plans. A 1% change in the assumed healthcare cost trend rate would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on the postretirement benefit obligation	$ 18	$ 16
Effect on total of service and interest cost	1	1

In managing the investments associated with the benefit plans, CenterPoint Energy's objective is to preserve and enhance the value of plan assets while maintaining an acceptable level of volatility. These objectives are expected to be achieved through an investment strategy that manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, CenterPoint Energy has adopted and maintains the following weighted average allocation targets for its benefit plans:

	Pension Benefits	Postretirement Benefits
Domestic equity securities	25-35%	14-24%
Global equity securities	7-13%	—
International equity securities	17-23%	3-13%
Debt securities	30-40%	68-78%
Real estate	0-5%	—
Cash	0-2%	0-2%

The following tables set forth by level, within the fair value hierarchy, CenterPoint Energy's pension plan assets at fair value as of December 31, 2009 and 2010:

	Fair Value Measurements at December 31, 2009 (in millions)			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash	$ 11	$ 11	$ —	$ —
Common collective trust funds (1)	733	—	733	—
Corporate bonds:				
Investment grade or above	193	—	192	1
High yield	2	—	2	—
Equity securities:				
International companies	162	160	2	—
U.S. companies	96	96	—	—
Cash received as collateral from securities lending	114	114	—	—
U.S. government backed agencies bonds	55	55	—	—
U.S. treasuries	50	50	—	—
Mortgage backed securities	39	—	39	—
Asset backed securities	27	—	24	3
Municipal bonds	22	2	20	—

Mutual funds (2)	21	21	—	—
International government bonds	12	—	12	—
Real estate	9	—	—	9
Obligation to return cash received as collateral from securities lending	(114)	(114)	—	—
Total	$ 1,432	$ 395	$ 1,024	$ 13

(1) 30% of the amount invested in common collective trust funds is in fixed income securities, 31% is in U.S. equities and 39% is in international equities.

(2) 48% of the amount invested in mutual funds is in fixed income securities and 52% is in U.S. equities.

	Fair Value Measurements at December 31, 2010 (in millions)			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash	$ 3	$ 3	$ —	$ —
Common collective trust funds (1)	890	—	890	—
Corporate bonds:				
Investment grade or above	122	—	122	—
Equity securities:				
International companies	133	133	—	—
U.S. companies	131	131	—	—
Cash received as collateral from securities lending	112	112	—	—
U.S. government backed agencies bonds	34	34	—	—
U.S. treasuries	62	62	—	—
Mortgage backed securities	8	—	8	—
Asset backed securities	10	—	10	—
Municipal bonds	28	—	28	—
Mutual funds (2)	55	55	—	—
International government bonds	17	—	17	—
Real estate	8	—	—	8
Obligation to return cash received as collateral from securities lending	(112)	(112)	—	—
Total	$ 1,501	$ 418	$ 1,075	$ 8

(1) 24% of the amount invested in common collective trust funds is in fixed income securities, 42% is in U.S. equities and 34% is in international equities.

(2) 74% of the amount invested in mutual funds is in fixed income securities and 26% is in U.S. equities.

The pension plan utilized both exchange traded and over-the-counter financial instruments such as futures, interest rate options and swaps that were marked to market daily with the gains/losses settled in the cash accounts. The pension plan did not include any holdings of CenterPoint Energy common stock as of December 31, 2009 or 2010.

The following tables present additional information about the changes in the fair value of the pension plan's level 3 investments for the years ended December 31, 2009 and 2010:

	Level 3 Investments Year Ended December 31, 2009 (in millions)			
	Corporate bonds	Asset backed securities	Real estate	Total

Balance, beginning of year	$ 1	$ 3	$ 14	$ 18
Unrealized losses relating to instruments still held at the reporting date	—	—	(5)	(5)
Balance, end of year	$ 1	$ 3	$ 9	$ 13

Level 3 Investments Year Ended December 31, 2010 (in millions)	Corporate bonds	Asset backed securities	Real estate	Total
Balance, beginning of year	$ 1	$ 3	$ 9	$ 13
Unrealized losses relating to instruments still held at the reporting date	—	—	(1)	(1)
Purchases, sales, issuances, and settlement (net)	—	(1)	—	(1)
Transfer out of Level 3	(1)	(2)	—	(3)
Balance, end of year	$ —	$ —	$ 8	$ 8

The following tables present by level, within the fair value hierarchy, CenterPoint Energy's postretirement plan assets at fair value as of December 31, 2009 and 2010, by asset category:

Fair Value Measurements at December 31, 2009 (in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs Level 3)
Mutual funds (1)	$ 146	$ 146	$ —	$ —
Total	$ 146	$ 146	$ —	$ —

(1) 65% of the amount invested in mutual funds is in fixed income securities, 26% is in U.S. equities and 9% is in international equities.

Fair Value Measurements at December 31, 2010 (in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs Level 3)
Mutual funds (1)	$ 144	$ 144	$ —	$ —
Total	$ 144	$ 144	$ —	$ —

(1) 73% of the amount invested in mutual funds is in fixed income securities, 19% is in U.S. equities and 8% is in international equities.

CenterPoint Energy contributed $8 million and $26 million to its non-qualified pension and postretirement benefits plans, respectively, in 2010. CenterPoint Energy expects to contribute approximately $35 million, $9 million and $18 million to its qualified pension, non-qualified pension and postretirement benefits plans, respectively, in 2011.

The following benefit payments are expected to be paid by the pension and postretirement benefit plans (in millions):

	Pension Benefits	Postretirement Benefit Plan Benefit Payments	Postretirement Benefit Plan Medicare Subsidy Receipts
2011	$ 142	$ 33	$ (4)
2012	148	34	(5)
2013	149	39	(5)
2014	149	40	(6)
2015	149	42	(6)
2016-2020	762	225	(42)

(c) Savings Plan

CenterPoint Energy has a tax-qualified employee savings plan that includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended (the Code), and an employee stock ownership plan (ESOP) under Section 4975(e)(7) of the Code. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 50% of eligible compensation. The Company matches 100% of the first 6% of each employee's compensation contributed. The matching contributions are fully vested at all times.

Participating employees may elect to invest all or a portion of their contributions to the plan in CenterPoint Energy common stock, to have dividends reinvested in additional shares or to receive dividend payments in cash on any investment in CenterPoint Energy common stock, and to transfer all or part of their investment in CenterPoint Energy common stock to other investment options offered by the plan.

The savings plan has significant holdings of CenterPoint Energy common stock. As of December 31, 2010, 21,012,609 shares of CenterPoint Energy's common stock were held by the savings plan, which represented approximately 22% of its investments. Given the concentration of the investments in CenterPoint Energy's common stock, the savings plan and its participants have market risk related to this investment.

CenterPoint Energy's savings plan benefit expenses were $39 million, $31 million and $34 million in 2008, 2009 and 2010, respectively.

(d) Postemployment Benefits

CenterPoint Energy provides postemployment benefits for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). The Company recorded postemployment benefit income of $1 million, $-0- and $1 million in 2008, 2009 and 2010, respectively.

Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2009 and 2010 was $29 million and $25 million, respectively, relating to postemployment obligations.

(e) Other Non-Qualified Plans

CenterPoint Energy has non-qualified deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of CenterPoint Energy. During 2008, 2009 and 2010, CenterPoint Energy recorded benefit expense relating to these plans of $4 million, $6 million and $5 million, respectively. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2009 and 2010 was $79 million and $78 million, respectively, relating to deferred compensation plans.

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 and recorded a cumulative effect adjustment of $15 million to increase other non-current liabilities and accumulated deficit as of January 1, 2008. Included in Benefit Obligations in CenterPoint Energy's Consolidated Balance Sheets at December 31, 2009 and 2010 was $19 million and $21 million, respectively, relating to split-dollar life insurance arrangements.

(f) Change in Control Agreements and Other Employee Matters

CenterPoint Energy has agreements with certain of its officers that generally provide, to the extent applicable, in the case of a change in control of CenterPoint Energy and termination of employment, for severance benefits of up to three times annual base salary plus bonus, and other benefits. These agreements are for a one-year term with automatic renewal unless action is taken by CenterPoint Energy's board of directors prior to the renewal.

As of December 31, 2010, approximately 30% of CenterPoint Energy's employees are subject to collective bargaining agreements. Collective bargaining agreements with two of CenterPoint Energy's unions, the Gas Workers Union Local No. 340 and the International Brotherhood of Electrical Workers Local No. 949, that collectively represent approximately 7% of CenterPoint Energy's employees are scheduled to expire in April and December 2011, respectively. CenterPoint Energy has a good relationship with these bargaining units and expects to negotiate new agreements in 2011.

(7) Derivative Instruments

CenterPoint Energy is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CenterPoint Energy utilizes derivative instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices, weather and interest rates on its operating results and cash flows.

(a) Non-Trading Activities

Derivative Instruments. CenterPoint Energy enters into certain derivative instruments to manage physical commodity price risks and does not engage in proprietary or speculative commodity trading. These financial instruments do not qualify or are not designated as cash flow or fair value hedges.

During the year ended December 31, 2008, CenterPoint Energy recorded increased natural gas revenues from unrealized net gains of $101 million and increased natural gas expense from unrealized net losses of $88 million, a net unrealized gain of $13 million. During the year ended December 31, 2009, CenterPoint Energy recorded decreased natural gas revenues from unrealized net losses of $80 million and decreased natural gas expense from unrealized net gains of $57 million, a net unrealized loss of $23 million. During the year ended December 31, 2010, CenterPoint Energy recorded increased natural gas revenues from unrealized net gains of $18 million and increased natural gas expense from unrealized net losses of $14 million, a net unrealized gain of $4 million.

Weather Hedges. CenterPoint Energy has weather normalization or other rate mechanisms that mitigate the impact of weather on its gas operations in Arkansas, Louisiana, Oklahoma and a portion of Texas. The remaining Gas Operations jurisdictions do not have such mechanisms. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of the gas operations in the remaining jurisdictions and in CenterPoint Houston's service territory.

In 2008, 2009 and 2010, CenterPoint Energy entered into heating-degree day swaps to mitigate the effect of fluctuations from normal weather on its financial position and cash flows for the respective winter heating seasons. The swaps were based on ten-year normal weather. During the years ended December 31, 2008, 2009 and 2010, CenterPoint Energy recognized losses of $17 million, $7 million and $6 million, respectively, related to these swaps. The losses were substantially offset by increased revenues due to colder than normal weather. Weather hedge losses are included in revenues in the Statements of Consolidated Income.

Hedging of Future Debt Issuances. CenterPoint Energy uses interest rate cash flow hedges in order to mitigate its exposure to variability in cash flows with respect to the future interest payments on designated borrowings. During the years ended December 31, 2008, 2009 and 2010 and as of December 31, 2009 and 2010, amounts related to CenterPoint Energy's interest rate cash flow hedges were not material.

(b) Derivative Fair Values and Income Statement Impacts

The following tables present information about CenterPoint Energy's derivative instruments and hedging activities. The first two tables provide a balance sheet overview of CenterPoint Energy's Derivative Assets and Liabilities as of December 31, 2009 and 2010, while the last table provides a breakdown of the related income statement impacts for the years ending December 31, 2009 and 2010.

Fair Value of Derivative Instruments

		December 31, 2009	
Total derivatives not designated as hedging instruments	Balance Sheet Location	Derivative Assets Fair Value (2) (3)	Derivative Liabilities Fair Value (2) (3)
		(in millions)	
Natural gas contracts (1)	Current Assets	$ 46	$ (7)
Natural gas contracts (1)	Other Assets	16	(1)
Natural gas contracts (1)	Current Liabilities	20	(123)
Natural gas contracts (1)	Other Liabilities	1	(86)
Indexed debt securities derivative	Current Liabilities	—	(201)
Total		$ 83	$ (418)

(1) Natural gas contracts are subject to master netting arrangements and are presented on a net basis in the Consolidated Balance Sheets. This netting causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets.

(2) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 674 billion cubic feet (Bcf) or a net 152 Bcf long position. Of the net long position, basis swaps constitute 71 Bcf and volumes associated with price stabilization activities of the Natural Gas Distribution business segment comprise 51 Bcf.

(3) The net of total non-trading derivative assets and liabilities is a $39 million liability as shown on CenterPoint Energy's Consolidated Balance Sheets, and is comprised of the natural gas contracts derivative assets and liabilities separately shown above offset by collateral netting of $95 million.

Fair Value of Derivative Instruments

		December 31, 2010	
Total derivatives not designated as hedging instruments	Balance Sheet Location	Derivative Assets Fair Value (2) (3)	Derivative Liabilities Fair Value (2) (3)
		(in millions)	
Natural gas contracts (1)	Current Assets	$ 55	$ (1)
Natural gas contracts (1)	Other Assets	15	—
Natural gas contracts (1)	Current Liabilities	10	(143)
Natural gas contracts (1)	Other Liabilities	—	(35)
Indexed debt securities derivative	Current Liabilities	—	(232)
Total		$ 80	$ (411)

(1) Natural gas contracts are subject to master netting arrangements and are presented on a net basis in the Consolidated Balance Sheets. This netting causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets.

(2) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 626 Bcf or a net 72 Bcf long position. Of the net long position, basis swaps constitute 63 Bcf and volumes associated with price stabilization activities of the Natural Gas Distribution business segment comprise 26 Bcf.

(3) The net of total non-trading derivative assets and liabilities is a $15 million liability as shown on CenterPoint Energy's Consolidated Balance Sheets, and is comprised of the natural gas contracts derivative assets and liabilities separately shown above offset by collateral netting of $84 million.

For CenterPoint Energy's price stabilization activities of the Natural Gas Distribution business segment, the settled costs of derivatives are ultimately recovered through purchased gas adjustments. Accordingly, the net unrealized gains and losses associated with these contracts are recorded as net regulatory assets. Realized and unrealized gains and losses on other derivatives are recognized in the Statements of Consolidated Income as revenue for retail sales derivative contracts and as natural gas expense for financial natural gas derivatives and non-retail related physical natural gas derivatives. Unrealized gains and losses on indexed debt securities are recorded as Other Income (Expense) in the Statements of Consolidated Income.

Income Statement Impact of Derivative Activity

Total derivatives not designated as hedging instruments	Income Statement Location	Year Ended December 31, 2009	Year Ended December 31, 2010
		(in millions)	
Natural gas contracts	Gains (Losses) in Revenue	$ 102	$ 90
Natural gas contracts (1)	Gains (Losses) in Expense: Natural Gas	(255)	(165)
Indexed debt securities derivative	Gains (Losses) in Other Income (Expense)	(68)	(31)
Total		$ (221)	$ (106)

(1) The Gains (Losses) in Expense: Natural Gas includes $(181) million and $(115) million of costs in 2009 and 2010, respectively, associated with price stabilization activities of the Natural Gas Distribution business segment that will be ultimately recovered through purchased gas adjustments.

(c) Credit Risk Contingent Features

CenterPoint Energy enters into financial derivative contracts containing material adverse change provisions. These provisions could require CenterPoint Energy to post additional collateral if the Standard & Poor's Rating Services or Moody's Investors Service, Inc. credit ratings of CenterPoint Energy, Inc. or its subsidiaries are downgraded. The total fair value of the derivative instruments that contain credit risk contingent features that are in a net liability position at December 31, 2009 and 2010 was $140 million and $107 million, respectively. The aggregate fair value of assets that are already posted as collateral was $65 million and $31 million, respectively, at December 31, 2009 and 2010. If all derivative contracts (in a net liability position) containing credit risk contingent features were triggered at December 31, 2009 and 2010, $75 million and $76 million, respectively, of additional assets would be required to be posted as collateral.

(d) Credit Quality of Counterparties

In addition to the risk associated with price movements, credit risk is also inherent in CenterPoint Energy's non-trading derivative activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. The following table shows the composition of counterparties to the non-trading derivative assets of CenterPoint Energy as of December 31, 2009 and 2010 (in millions):

	December 31, 2009		December 31, 2010	
	Investment Grade(1)	Total	Investment Grade(1)	Total

Energy marketers	$ 6	$ 6	$ 5	$ 8
Financial institutions	2	4	1	1
Retail end users (2)	1	44	—	60
Total	$ 9	$ 54	$ 6	$ 69

(1) "Investment grade" is primarily determined using publicly available credit ratings and considering credit support (such as parent company guaranties) and collateral, which encompass cash and standby letters of credit. For unrated counterparties, CenterPoint Energy determines a synthetic credit rating by performing financial statement analysis and considering contractual rights and restrictions and collateral.

(2) Retail end users represent customers who have contracted to fix the price of a portion of their physical gas requirements for future periods.

(8) Fair Value Measurements

Assets and liabilities are recorded at fair value in the Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined in this guidance and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities, are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. The types of assets carried at Level 1 fair value generally are exchange-traded derivatives and equity securities.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. A market approach is utilized to value CenterPoint Energy's Level 2 assets or liabilities.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls has been determined based on the lowest level input that is significant to the fair value measurement in its entirety. Unobservable inputs reflect CenterPoint Energy's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. CenterPoint Energy develops these inputs based on the best information available, including CenterPoint Energy's own data. A market approach is utilized to value CenterPoint Energy's Level 3 assets or liabilities.

CenterPoint Energy determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period. For the year ended December 31, 2010, there were no significant transfers between levels.

The following tables present information about CenterPoint Energy's assets and liabilities (including derivatives that are presented net) measured at fair value on a recurring basis as of December 31, 2009 and 2010, and indicate the fair value hierarchy of the valuation techniques utilized by CenterPoint Energy to determine such fair value.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance as of December 31, 2009
			(in millions)		
Assets					
Corporate equities	$ 301	$ —	$ —	$ —	$ 301
Investments, including money market funds	41	—	—	—	41
Derivative assets	1	77	5	(29)	54
Total assets	$ 343	$ 77	$ 5	$ (29)	$ 396
Liabilities					

Indexed debt securities derivative	$	—	$	201	$	—	$	—		$	201
Derivative liabilities		12		194		11		(124	)		93
Total liabilities	$	12	$	395	$	11	$	(124	)	$	294

(1) Amounts represent the impact of legally enforceable master netting agreements that allow CenterPoint Energy to settle positive and negative positions and also include cash collateral of $95 million posted with the same counterparties.

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	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3) (in millions)	Netting Adjustments (1)	Balance as of December 31, 2010
Assets					
Corporate equities	$ 368	$ —	$ —	$ —	$ 368
Investments, including money market funds	54	—	—	—	54
Derivative assets	—	73	7	(11)	69
Total assets	$ 422	$ 73	$ 7	$ (11)	$ 491
Liabilities					
Indexed debt securities derivative	$ —	$ 232	$ —	$ —	$ 232
Derivative liabilities	8	167	4	(95)	84
Total liabilities	$ 8	$ 399	$ 4	$ (95)	$ 316

(1) Amounts represent the impact of legally enforceable master netting agreements that allow CenterPoint Energy to settle positive and negative positions and also include cash collateral of $84 million posted with the same counterparties.

The following tables present additional information about assets or liabilities, including derivatives that are measured at fair value on a recurring basis for which CenterPoint Energy has utilized Level 3 inputs to determine fair value:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Derivative assets and liabilities, net Year Ended December 31,		
	2008	2009 (in millions)	2010
Beginning balance	$ (3)	$ (58)	$ (6)
Total unrealized gains or (losses):			