CenterPoint®
Energy

Always There.®

STAYING FOCUSED

2008 ANNUAL REPORT

HOW DO YOU
ACHIEVE CONSISTENT
PERFORMANCE?

HOW DO YOU
SUCCEED IN CHANGING
MARKET CONDITIONS?

RIGHT STRATEGY.
RIGHT ASSETS.
RIGHT PEOPLE.

CenterPoint Energy's solid performance is achieved by staying focused on our portfolio of electric and natural gas delivery businesses.

As we continue to build and operate energy delivery systems to serve our customers today and tomorrow, we will strive toward our vision: to be recognized as America's leading energy delivery company…and more.

THE STRENGTH OF A BALANCED PORTFOLIO

ELECTRIC TRANSMISSION & DISTRIBUTION

2+ Million Metered Customers

5,000-Square-Mile Electric Service Territory In The Houston Area

$545 Million Operating Income

COMPETITIVE NATURAL GAS SALES & SERVICES

Marketed 528 Billion Cubic Feet Of Natural Gas To Commercial, Industrial And Wholesale Customers In The Central And Eastern United States

$62 Million Operating Income

NATURAL GAS DISTRIBUTION

3.2 Million Customers In Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma And Texas

$215 Million Operating Income

FIELD SERVICES

3,600 Miles Of Gathering Lines

Gathered 421 Billion Cubic Feet Of Natural Gas In 2008

$147 Million Operating Income Plus $15 Million Equity Income From A Jointly Owned Natural Gas Processing Plant

INTERSTATE PIPELINES

8,000 Miles Of Pipe

Transported More Than 1,500 Billion Cubic Feet Of Natural Gas In 2008

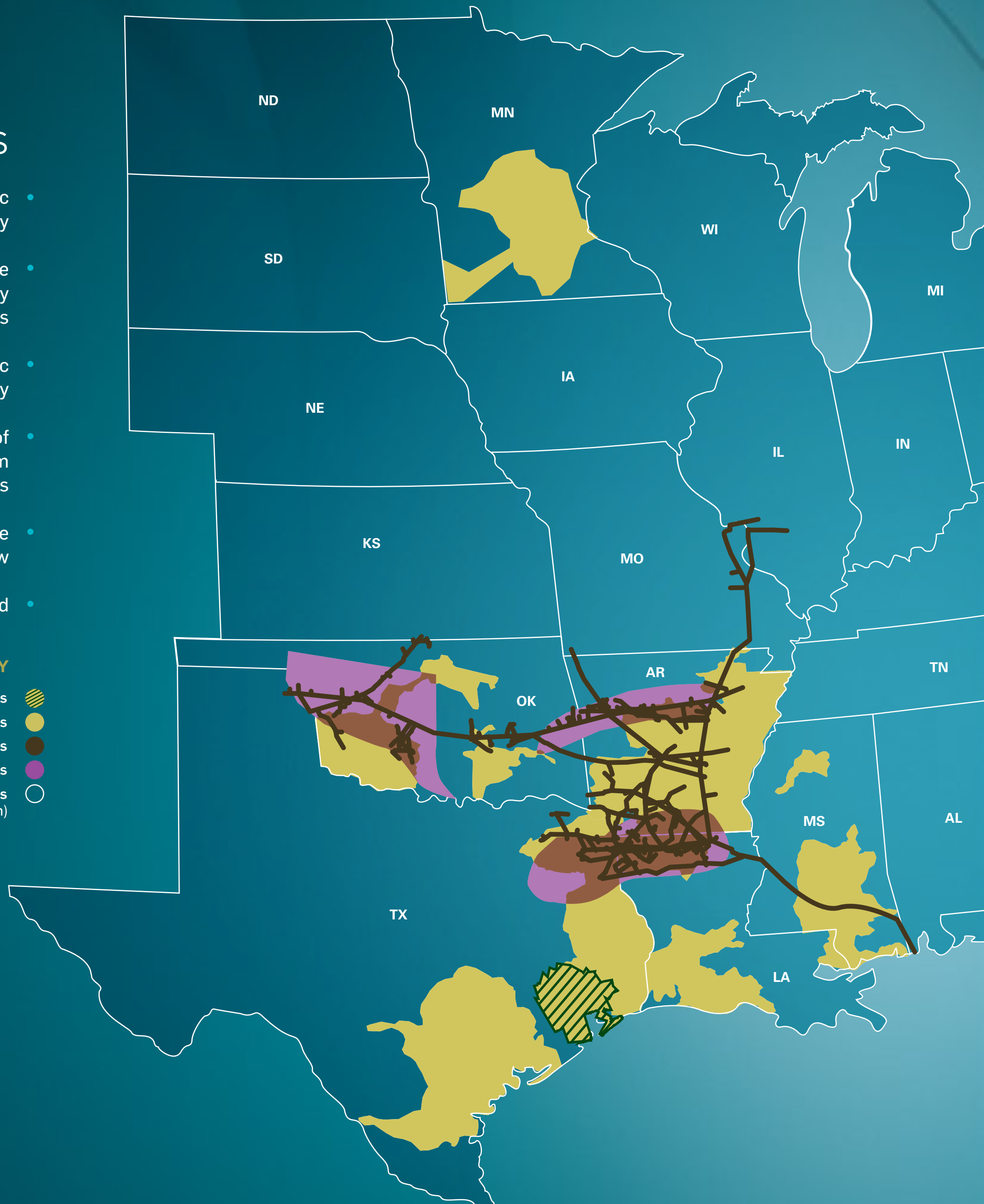
$293 Million Operating Income

CODE OF ETHICS

The CenterPoint Energy Ethics and Compliance Code is based on our core values of **INTEGRITY**, **ACCOUNTABILITY**, **INITIATIVE** and **RESPECT**, and reflects the basic ethical principles that guide our conduct every day. Copies of our Ethics and Compliance Code are available in the Investors section of our Web site at CenterPointEnergy.com.

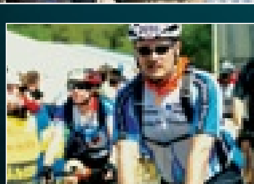
OUR OPERATIONS

- Large scale, domestic energy delivery company
- Attractive service territories and strategically located assets
- Geographic, economic and regulatory diversity
- Approximately 80% of operating income from regulated operations
- Predictable, stable earnings and cash flow
- Attractive dividend



MAP KEY

- Electric Operations
- Natural Gas Operations
- Pipelines
- Field Services
- Competitive Natural Gas Sales & Services (includes all states shown)



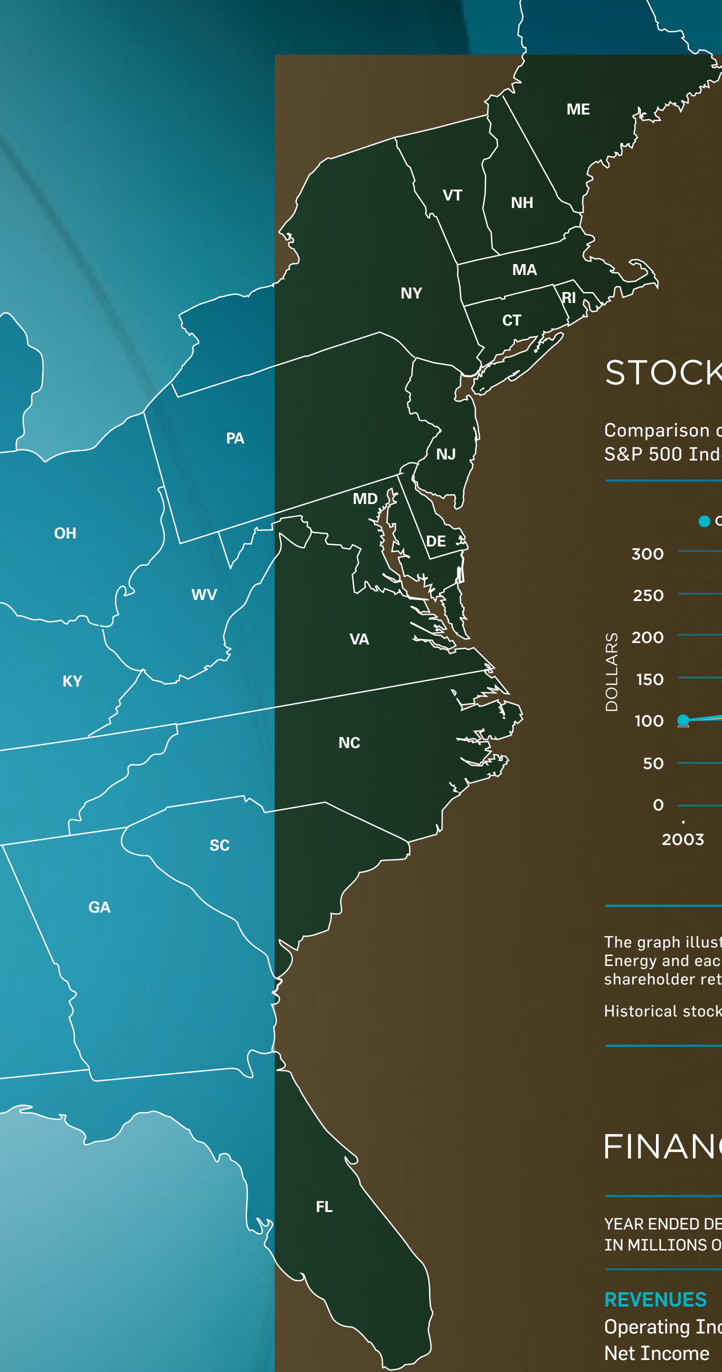
OUR PEOPLE

AFTER THE STORM

In the aftermath of Hurricane Ike, more than 90 percent of our more than 2 million customers were left without power. Working 16-hour shifts, over 11,000 skilled workers from around the country and Canada worked side-by-side with more than 5,000 of our employees to restore power to the greater Houston area in 18 days. The Edison Electric Institute (EEI) presented us with the EEI Emergency Recovery Award for our Hurricane Ike restoration efforts. We also received an EEI Emergency Assistance Award for helping other utilities following a 2007 ice storm in Oklahoma; Hurricane Dolly, which struck south Texas in 2008; and Hurricane Gustav, which hit Louisiana in 2008.

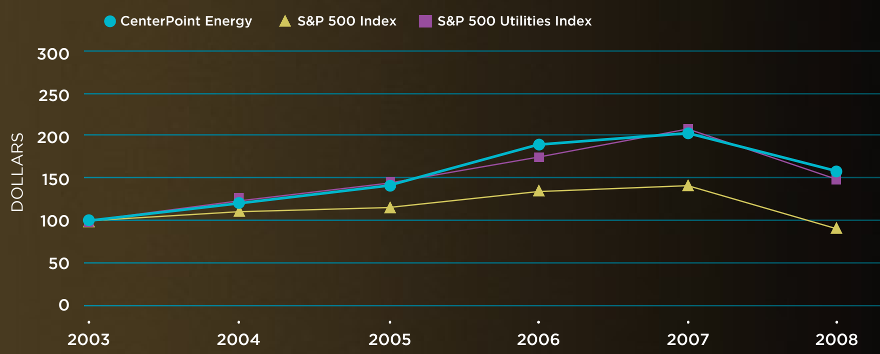
IN THE COMMUNITY

CenterPoint Energy and our employees contributed nearly $4.3 million for nonprofit organizations. Employees also volunteered approximately 166,000 hours in their communities.



STOCK PERFORMANCE GRAPH

Comparison of five-year cumulative total return among CenterPoint Energy, S&P 500 Index and S&P 500 Utilities Index for fiscal years ended December 31



The graph illustrates the value on 12/31/08 of $100 invested in the common stock of CenterPoint Energy and each reference group on 12/31/03. The calculation of CenterPoint Energy's total shareholder return assumes dividends were reinvested in company stock.

Historical stock performance is not necessarily indicative of future performance.

FINANCIAL HIGHLIGHTS

YEAR ENDED DECEMBER 31 IN MILLIONS OF DOLLARS (EXCEPT PER SHARE AMOUNTS)	2006	2007	**2008**
REVENUES	$ 9,319	$ 9,623	**$ 11,322**
Operating Income	1,045	1,185	**1,273**
Net Income	432	399	**447**
PER SHARE OF COMMON STOCK			
Net Income, Basic	1.39	1.25	**1.33**
Net Income, Diluted	1.33	1.17	**1.30**
Book Value – Year End	4.96	5.61	**5.89**
Market Value – Year End	16.58	17.13	**12.62**
Common Dividend Paid	0.60	0.68	**0.73**
CAPITALIZATION			
Transition Bonds (Includes Current Portion)	2,407	2,260	**2,589**
Other Long-Term Debt (Includes Current Portion)	6,593	7,419	**7,925**
Common Stock Equity	1,556	1,810	**2,037**
Total Capitalization (Includes Current Portion)	10,556	11,489	**12,551**
Total Assets	17,633	17,872	**19,676**
Capital Expenditures	$ 1,121	$ 1,011	**$ 1,053**
Common Stock Outstanding (In Thousands)	313,652	322,719	**346,089**
Number of Common Shareholders (In Actual Numbers)	52,085	49,271	**47,405**
Number of Employees (In Actual Numbers)	8,623	8,568	**8,801**

OUR BUSINESSES CONTINUE TO PERFORM WELL

UNDER A VARIETY OF MARKET CONDITIONS

[LEFT TO RIGHT]

Milton Carroll
Chairman

David M. McClanahan
President and CEO

DEAR SHAREHOLDER,

2008 was an excellent year for your company. Our employees responded admirably in the aftermath of Hurricane Ike, and in the face of global economic turmoil and the upheaval in the financial markets, our businesses delivered earnings significantly higher than the previous year. Our diversified portfolio of electric and natural gas delivery businesses continues to perform well under a variety of market conditions.

CenterPoint Energy's net income increased by $48 million to $447 million, an increase of 12 percent over 2007. Earnings per share were $1.30 compared to $1.17 from the previous year. We raised our quarterly common stock dividend by more than 7 percent in 2008. In January 2009, we raised our quarterly dividend by 4 percent, marking the fourth consecutive year we have raised our dividend since emerging from our early transition years as an independent company. Our goal is to return 50 to 75 percent of our sustainable earnings to shareholders each year.

Despite our strong earnings, the decline in the stock market last year impacted the value of CenterPoint Energy's stock. While our total shareholder return last year was -22.5 percent, our performance was better than the overall stock market as well as the S&P 500 Utilities Index.

Our earnings were driven by the solid performance of our businesses, which serve essential energy delivery needs of customers across the country. Each of our businesses overcame challenges and executed their business plans very well. Responding to these challenges also helped us prepare for what lies ahead.

Our **electric transmission and distribution** business, which serves more than 2 million customers in the Houston area, overcame the impact of Hurricane Ike and increased core operating income from transmission and distribution operations, reporting $407 million compared to $400 million in 2007. Customer growth, warmer weather and increased usage all drove last year's performance. Though Hurricane Ike dealt a staggering blow to our service territory, our employees rose to the challenge as they always do. We restored electricity to most customers within two weeks and to all customers capable of receiving power within 18 days, a significant achievement of which we are quite proud.

Our **natural gas distribution** business had a good year with operating income of $215 million, a decline of only $3 million from the previous year's record high of $218 million. Economic conditions, energy conservation and reduced usage offset the benefits of customer growth and rate increases. We continue to make progress toward decoupling natural gas rates to separate our revenue from the volume of natural gas sold. These progressive rate designs allow us to actively promote conservation and energy efficiency and minimize the impact of reduced customer use on our earnings, thereby aligning the interests of our company with those of our customers.

Our **interstate pipelines** business reported record results for the sixth consecutive year with $293 million in operating income, an increase of 24 percent over 2007. In addition to bringing new pipelines and capacity into service, we maximized the value of our core pipeline system by renewing contracts with key customers and capturing incremental revenue through ancillary services and system management. Our assets are strategically located in the mid-continent region where new drilling techniques have stimulated natural gas exploration and production, providing us opportunities for further growth.

This same strong drilling activity also drove record results for the sixth consecutive year for our **field services** business, which had operating income of $147 million in 2008, an increase from $99 million the previous year. We continued to invest in gathering, processing and treating facilities, and for the third consecutive year, we connected more than 400 wells to our system.

Our **competitive natural gas sales and services** business had a solid year, even though its $62 million in operating income represented a decrease from $75 million in 2007. The timing of mark-to-market losses and inventory write-downs offset improved operating margins, increased natural gas throughput, and significant growth in revenues and customer count.

MEETING THE NATION'S CHANGING ENERGY DEMANDS

With a new administration in Washington, the focus of the nation's energy policies are expected to shift dramatically. Climate change concerns are projected to drive initiatives to reduce carbon emissions and increase energy conservation. Many observers believe this will lead to increased use of natural gas for power generation until clean coal technologies are developed and more nuclear power plants are built. Natural gas has the lowest carbon footprint of any of the fossil fuels. In the near term, we expect policy makers to place an emphasis on energy conservation, because there is no better way to reduce carbon emissions than to use less energy.

We are well positioned to respond to these concerns in ways that will benefit both our customers and our shareholders. Energy-efficiency programs are not new to us. We have been helping our customers use energy more wisely for decades. For example, in Houston, through our ENERGY STAR new homes program, we have reduced electric demand by 130 megawatts over the last eight years. In Minnesota, our natural gas conservation improvement programs have reduced usage by 10.7 billion cubic feet over 16 years.

The future is even more promising. In December 2008, we received approval to install more than 2 million advanced electric meters that have the potential to elevate energy conservation to a new level. Through these meters, information about

OFFICERS

[FRONT ROW, LEFT TO RIGHT]
David M. McClanahan
Scott E. Rozzell
Gary L. Whitlock
Thomas R. Standish

[BACK ROW, LEFT TO RIGHT]
C. Gregory Harper
Joseph B. McGoldrick
James M. Dumler
Wayne D. Stinnett, Jr.

BOARD OF DIRECTORS

[FRONT ROW, LEFT TO RIGHT]
Robert T. O'Connell
Derrill Cody
Janiece M. Longoria
Milton Carroll
David M. McClanahan
Susan O. Rheney

[BACK ROW: LEFT TO RIGHT]
Peter S. Wareing
Sherman M. Wolff
O. Holcombe Crosswell
Michael E. Shannon
Thomas F. Madison
Donald R. Campbell
Michael P. Johnson

energy consumption and usage patterns will be made available to our customers. Pilot studies across the country indicate substantial reductions in electricity usage are possible once consumers understand their usage on a real-time basis and are given tools to respond. This new system is expected to take five years to fully deploy at an estimated cost of $640 million. We will recover our investment through a special tariff that has been approved by the Public Utility Commission of Texas.

Despite increased energy conservation, demand for electricity and, therefore, the demand for clean natural gas, is expected to increase. This will, in turn, drive the need for infrastructure to get new gas supplies to market. Some of the most prolific new natural gas reserves are being produced from unconventional sources in Arkansas, Louisiana, Oklahoma and Texas. Over the last several years, we have made record investments in our gas gathering, processing and pipeline facilities and are well positioned to serve these new drilling areas and meet growing demand. We will continue to pursue new investment opportunities in and around our service territory.

THE CHALLENGES FOR 2009

As we write this letter, the country faces considerable challenges. Financial markets are in turmoil. The nation is in a recession that is expected to impact economic growth at least through this year and, most likely, into 2010. Your company is not immune to the impact of these conditions. Overall customer growth in our electric and gas utilities service territories is expected to be modest, at best, in 2009. Energy markets are also being impacted, creating uncertainty about the timing of some projects. The steep decline in the stock market last year took its toll on the value of the assets in our pension plans. As a result, non-cash pension expense will increase approximately $88 million, pressuring our 2009 earnings.

We have worked hard to strengthen our liquidity and cash flow to weather these conditions, and we are closely managing our spending given these uncertain economic times. While we expect 2009 to be challenging, we are well positioned and are committed to the long-term growth of your company.

In closing, we once again want to thank our employees for their hard work and dedication. We are extremely proud of their outstanding efforts in 2008.

You can be assured that we will continue to work hard to earn your trust. We appreciate your confidence, and we will keep striving to increase the value of your investment.

Sincerely,

Milton Carroll

Milton Carroll
Chairman

David M. McClanahan

David M. McClanahan
President and CEO

ELECTRIC TRANSMISSION AND DISTRIBUTION

A CENTURY OF SERVICE;

INVESTING IN THE FUTURE

Our electric transmission and distribution business had a good year, in spite of Hurricane Ike. We reported operating income of $545 million, consisting of $407 million from the electric utility, $133 million related to transition bonds and $5 million from the competition transition charge. In 2008, we added nearly 31,000 customers, and we invested more than $330 million in new infrastructure to serve both our new and existing customers.

We overcame the largest power outage in Texas history when Hurricane Ike hit the Houston-Galveston area in September. Our electric infrastructure held up well,

with less than 1 percent of our poles destroyed or needing to be replaced. Uprooted trees and flying debris, however, damaged or severed power lines throughout our service territory causing outages that affected more than 2 million, or 90 percent, of our customers and more than 3 million customers overall in Texas. With the help of 11,000 line mechanics and tree trimmers from 35 states and Canada, we safely restored service within 18 days and limited the loss of revenue to about $17 million. We are currently working within the regulatory process to recover the estimated $600-650 million it cost to restore the system.

We have begun the implementation of leading-edge technology to dramatically transform the way electricity is managed. This is a critical step to move the electric grid into the digital age. We received regulatory approval in December 2008 to install more than 2 million advanced meters over the next five years, beginning in March 2009, to meet the future needs of the Texas restructured market place. This technology will provide the remote capability for meter reading, connection and disconnection of service, and customers' operation of thermostats and other electric devices. These innovative meters 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.

Other environmentally friendly projects include supporting the installation of LED traffic signals in the City of Houston, converting off-road vehicles such as forklifts to electric motors, and testing plug-in hybrid electric vehicles. For the seventh consecutive year, we received the U.S. Environmental Protection Agency's ENERGY STAR Sustained Excellence Award.


NUMBER OF CUSTOMERS PER STATE AT YEAR END
OKLAHOMA 105,000
LOUISIANA 251,000
ARKANSAS 445,000
MISSISSIPPI 122,000
MINNESOTA 798,000
TEXAS 1.5 MILLION

NATURAL GAS DISTRIBUTION

ALIGNING THE INTERESTS OF OUR COMPANY,

CUSTOMERS AND THE ENVIRONMENT

Our natural gas distribution business reported operating income of $215 million, a decline of only $3 million from 2007 record earnings. These results reflected the impacts of the struggling economy, reduced customer energy use and volatile natural gas prices. Across our six-state service area, we added nearly 25,000 customers.

We continue to seek approval by our regulators of natural gas rates that minimize the impacts of weather and reduced customer use. These progressive rate designs support the promotion of energy conservation and better align the interests of our company and our customers. As part of an overall settlement in our Texas Coast jurisdiction, we implemented a new annual cost-of-service adjustment mechanism, a concept we hope to implement in other jurisdictions.

In Minnesota, as part of a $59.8 million rate request, we proposed a pilot program with a rate mechanism that separates the company's revenue from the volume of natural gas sold. We expect the Minnesota Public Utilities Commission to make a final decision in January 2010. We also implemented a weather adjustment rate mechanism in Oklahoma.

We continue to focus on increasing productivity and deploying new technologies to help us control costs and improve customer service.

Finally, customers ranked us first in the Midwest Region in the J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠, and customers in the South gave us significantly higher overall ratings than in 2007.

INTERSTATE PIPELINES

CAPTURING OPPORTUNITIES, BUILDING CONNECTIONS

Our interstate pipelines business achieved its sixth consecutive year of record earnings with operating income of $293 million in 2008.

Drilling and production activity within our footprint continues to provide system expansion opportunities. Completion of the third phase of our 172-mile Carthage to Perryville pipeline in April 2008 brought its capacity to 1.5 billion cubic feet per day (Bcf/day). In September, gas began flowing through our 270-mile Southeast Supply Header, a joint venture with Spectra Energy that has capacity for 1 Bcf/day. Also, we recently completed our expansion projects and added the Cove, Bierne and Poteau compressor stations on existing pipelines. Overall, we increased throughput by more than 25 percent over 2007, and producer interest near our facilities remains high.

We tailor our services to meet regulatory, customer and producer expectations, and we anticipate benefiting from improved planning and scheduling processes. We increased our ability to serve off-system customers located on the east side of our system, added new transportation and pooling services and are securing regulatory approvals while assessing customer interest for future expansions. We renewed a contract for an additional five years with one of our largest customers, Laclede Gas Company.

Maintaining strong customer relationships is an important driver of business results, and we continue to be very pleased with our customer satisfaction and retention rates.


1,538 BCF
2008
1,216 BCF
2007
939 BCF
2006
ANNUAL THROUGHPUT
CAT

FIELD SERVICES

RECORD PERFORMANCE;

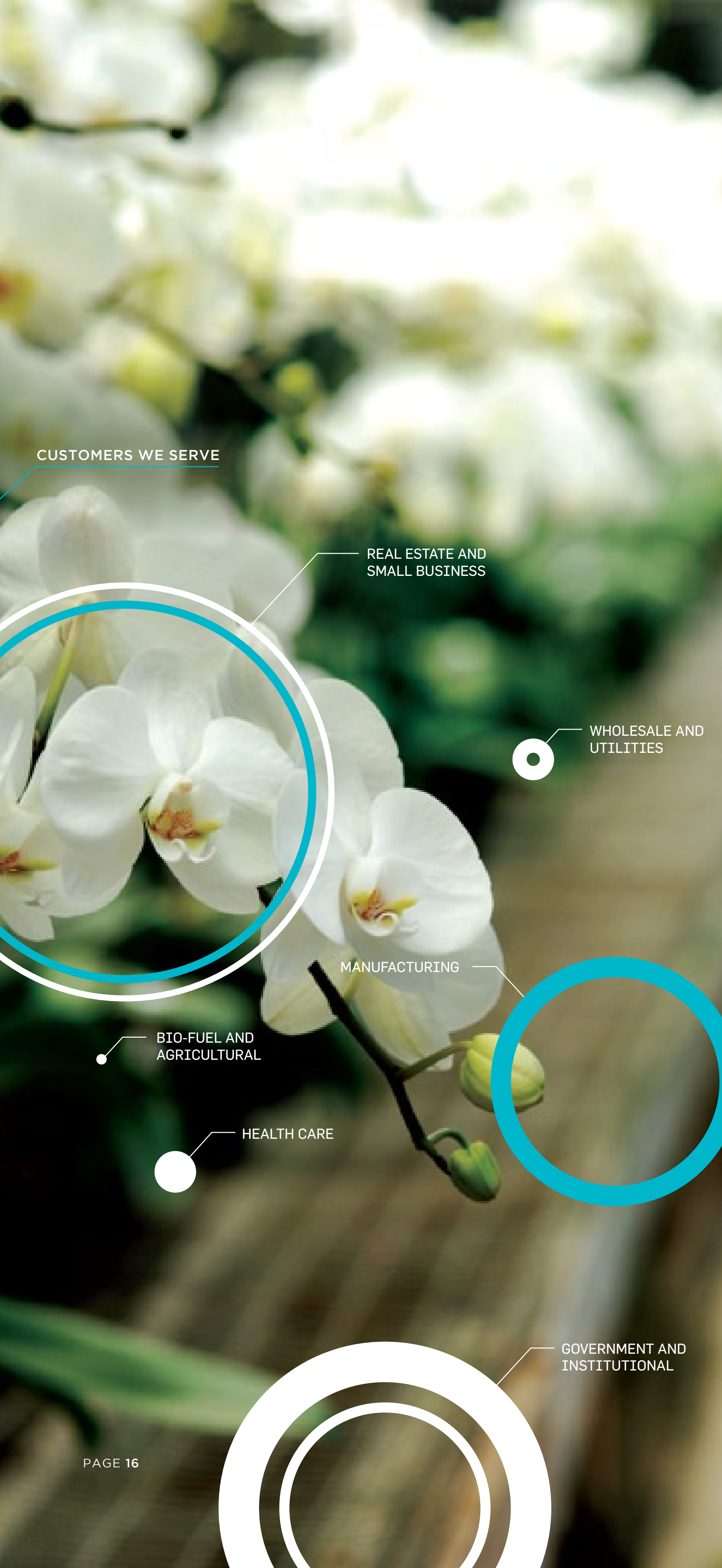
POSITIONED FOR GROWTH

For the sixth consecutive year, Field Services had record performance with operating income of $147 million plus equity income of $15 million from a jointly owned natural gas processing plant.

As a midstream natural gas gathering and processing provider, we added more than 475 new well connections to our system.

We also increased compression by 14 percent and throughput by 6 percent to achieve a year-end throughput of 1.15 Bcf/day. We completed a number of new gathering and processing projects, including a new 0.2 Bcf/day refrigeration plant.

With operations in and around traditional natural gas production basins of Arkoma, Anadarko and ArkLaTex, and in the unconventional shale areas of Fayetteville, Haynesville and Woodford, we are well positioned to continue capturing growth opportunities.



COMPETITIVE NATURAL GAS SALES AND SERVICES

EXPANDING OUR PRESENCE, EXTENDING OUR SERVICES

CenterPoint Energy Services, our competitive natural gas sales and services business, had a good year with operating income of $62 million.

We have a strong presence in growing regions and markets, and we have a diverse portfolio of customers, such as utilities, health care, manufacturing and small businesses, including an orchid nursery (pictured) in the Midwest. Overall, we added more than 2,600 industrial and commercial customers, including a group of commercial businesses in the Chicago area. This brings our total customer count to more than 9,700, an increase of 37 percent from the previous year. Extending our services within the bio-fuels industry, we now serve more than 30 bio-refining plants, including Poet, the largest ethanol producer in the U.S. We also are connecting new bio-methane plants that produce energy from animal waste and landfills.

Well positioned to meet the natural gas needs of current and future customers, we have more than 1 Bcf/day of firm transportation capacity and approximately 11 Bcf of underground storage capacity. We are accessing some of the most prolific shale production areas in the country to provide our customers with lower energy costs.

FORM 10-K

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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from__________________to_________________

Commission File Number 1-31447

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 ☑ No ☐

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

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

Indicate by check mark 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 each 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. ☑

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 ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of the voting stock held by non-affiliates of CenterPoint Energy, Inc. (Company) was $5,451,652,076 as of June 30, 2008, 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 13, 2009, the Company had 347,404,023 shares of Common Stock outstanding. Excluded from the number of shares of Common Stock outstanding are 166 shares held by the Company as treasury stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2009 Annual Meeting of Shareholders of the Company, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2008, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

TABLE OF CONTENTS

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," "intend," "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 of this report.

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 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 our audit, compensation, finance and governance committees of the 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 continue to be 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 are 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 the only business of CenterPoint Energy that continues to engage in electric utility operations. It 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 sales of electric energy at retail or wholesale, 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 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 electric transmission and 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 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 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 includes an aggregate net generating capacity of approximately 73,000 megawatts (MW). 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 Council (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 amended 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 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 Reliant Energy, Inc. (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.

Review by the Texas Supreme Court of the court of appeals decision is at the discretion of the court. In November 2008, the Texas Supreme Court requested the parties to the Petitions for Review to submit briefs on the merits of the issues raised. Briefing at the Texas Supreme Court should be completed in the second quarter of 2009. Although the Texas Supreme Court has not indicated whether it will grant review of the lower court's decision, its request for full briefing on the merits allowed the parties to more fully explain their positions. There is no prescribed time in which the Texas Supreme Court must determine whether to grant review or, if review is granted, for a decision by that court. 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 and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $170 million to $385 million (pre-tax) plus interest subsequent to December 31, 2008.

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, for 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. In its opinion, the court of appeals ordered that this issue be remanded to the Texas Utility Commission, as that commission requested. No party, in the petitions for review or briefs filed with the Texas Supreme Court, has challenged that order by the court of appeals, though the Texas Supreme Court, if it grants review, will have 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 or administrative process. Although the Texas Utility Commission 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 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 the 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 of the appellants have requested further review from the Texas Supreme Court. The ultimate outcome of this matter cannot be predicted at this time. However, the Company does not expect the disposition of this matter to have a material adverse effect on our or CenterPoint Houston's financial condition, results of operations or cash flows.

During the years ended December 31, 2006, 2007 and 2008, CenterPoint Houston recognized approximately $55 million, $42 million and $5 million, respectively, in operating income from the CTC. Additionally, during the years ended December 31, 2006, 2007 and 2008, CenterPoint Houston recognized approximately $13 million, $14 million and $13 million, respectively, of the allowed equity return not previously recognized. As of December 31, 2008, we have not recognized an allowed equity return of $207 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates.

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.

Hurricane Ike

CenterPoint Houston's electric delivery system suffered substantial damage as a result of Hurricane Ike, which struck the upper Texas coast early Saturday, September 13, 2008.

The strong Category 2 storm initially left more than 90% of CenterPoint Houston's more than 2 million metered customers without power, the largest outage in CenterPoint Houston's 130-year history. Most of the widespread power outages were due to power lines damaged by downed trees and debris blown by Hurricane Ike's winds. In addition, on Galveston Island and along the coastal areas of the Gulf of Mexico and Galveston Bay, the storm surge and flooding from rains accompanying the storm caused significant damage or destruction of houses and businesses served by CenterPoint Houston.

CenterPoint Houston estimates that total costs to restore the electric delivery facilities damaged as a result of Hurricane Ike will be in the range of $600 million to $650 million. As is common with electric utilities serving coastal regions, the poles, towers, wires, street lights and pole mounted equipment that comprise CenterPoint Houston's transmission and distribution system are not covered by property insurance, but office buildings and warehouses and their contents and substations are covered by insurance that provides for a maximum deductible of $10 million. Current estimates are that total losses to property covered by this insurance were approximately $17 million.

In addition to storm restoration costs, CenterPoint Houston lost approximately $17 million in revenue through December 31, 2008. Within the first 18 days after the storm, CenterPoint Houston had restored power to all customers capable of receiving it.

CenterPoint Houston has deferred the uninsured storm restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. As a result, storm restoration costs did not affect our or CenterPoint Houston's reported net income for 2008. As of December 31, 2008, CenterPoint Houston recorded an increase of $145 million in construction work in progress and $435 million in regulatory assets for restoration costs incurred through December 31, 2008. Approximately $73 million of these costs are based on estimates and are included in accounts payable as of December 31, 2008. Additional restoration costs will continue to be incurred in 2009.

Assuming necessary enabling legislation is enacted by the Texas Legislature in the session that began in January 2009, CenterPoint Houston expects to seek a financing order from the Texas Utility Commission to obtain recovery of its storm restoration costs through the issuance of non-recourse securitization bonds similar to the storm recovery bonds issued by another Texas utility following the hurricanes that affected that utility's service territories in 2005. Assuming those bonds are issued, CenterPoint Houston will recover the amount of storm restoration costs determined by the Texas Utility Commission to have been prudently incurred out of the bond proceeds, with the bonds being repaid over time through a charge imposed on customers. Alternatively, if securitization is not available, recovery of those costs would be sought through traditional regulatory mechanisms. Under its 2006 rate case settlement, CenterPoint Houston is entitled to seek an adjustment to rates in this situation, even though in most instances its rates are frozen until 2010.

Customers

CenterPoint Houston serves nearly all of the Houston/Galveston metropolitan area. CenterPoint Houston's customers consist of 79 REPs, which sell electricity to over 2 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 minimal creditworthiness criteria established by, the Texas Utility Commission. Two of the REPs in CenterPoint Houston's service area are subsidiaries of RRI. Sales to subsidiaries of RRI represented approximately 56%, 51% and 48% of CenterPoint Houston's transmission and distribution revenues in 2006, 2007 and 2008, respectively. CenterPoint Houston's billed receivables balance from REPs as of December 31, 2008 was $141 million. Approximately 46% of this amount was owed by subsidiaries of RRI. CenterPoint Houston does not have long-term contracts with any of its customers. It operates on a continuous billing cycle, with meter readings being conducted and invoices being distributed to REPs each business day.

Advanced Metering System and Distribution 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 plans to begin 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 will recover 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, beginning in February 2009, will be $3.24 per month; thereafter, the surcharge is scheduled to be 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 projects capital expenditures of approximately $640 million for the installation of the advanced meters and corresponding communication and data management systems over the five-year deployment period.

CenterPoint Houston is also pursuing possible deployment of an electric distribution grid automation strategy that involves the implementation of an "Intelligent Grid" 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 and maintenance of the CenterPoint Houston distribution system. These improvements would be expected to contribute to fewer and shorter outages, better customer service, improved operations costs, improved security and more effective use of our workforce. Texas Utility Commission approval and appropriate rate treatment would be sought in connection with any actual deployment of this technology.

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, 2008, CenterPoint Houston had outstanding approximately $2.6 billion aggregate principal amount of general mortgage bonds under the General Mortgage, including approximately $527 million held in trust to secure pollution control bonds for which CenterPoint Energy is obligated, $600 million securing borrowings under a credit facility which was unutilized and approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had outstanding approximately $253 million aggregate principal amount of first mortgage bonds under the Mortgage, including approximately $151 million held in trust to secure certain pollution control bonds for which CenterPoint Energy is 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 $1.8 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, 2008. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions. In January 2009, CenterPoint Houston issued $500 million aggregate principal amount of general mortgage bonds in a public offering.

Electric Lines — Overhead. As of December 31, 2008, CenterPoint Houston owned 27,603 pole miles of overhead distribution lines and 3,727 circuit miles of overhead transmission lines, including 423 circuit miles operated at 69,000 volts, 2,088 circuit miles operated at 138,000 volts and 1,216 circuit miles operated at 345,000 volts.

Electric Lines — Underground. As of December 31, 2008, CenterPoint Houston owned 19,690 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, 2008, CenterPoint Houston owned 229 major substation sites having a total installed rated transformer capacity of 51,400 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 3.2 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 2008, approximately 43% of Gas Operations' total throughput was to residential customers and approximately 57% was to commercial and industrial customers.

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, and natural gas transportation for, residential, commercial and industrial customers is seasonal. In 2008, 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.

Gas Operations also suffered some damage to its system in Houston, Texas and in other portions of its service territory across Texas and Louisiana as a result of Hurricane Ike. As of December 31, 2008, Gas Operations has deferred approximately $4 million of costs related to Hurricane Ike for recovery as part of future natural gas distribution rate proceedings.

Supply and Transportation. In 2008, 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 2008 included BP Canada Energy Marketing Corp. (13.4% of supply volumes), Tenaska Marketing Ventures (11.5%), Oneok Energy Marketing (10.2%), Coral Energy Resources (6.6%) and Cargill, Inc. (5.8%). Numerous other suppliers provided the remaining 52.5% 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 fifteen years. Gas Operations anticipates that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

We actively engage in commodity price stabilization pursuant to annual gas supply plans presented to and/or filed with each of our 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). Our 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 MMcf per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf natural gas equivalent). It owns liquefied natural gas plant facilities with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf natural gas equivalent) and a production rate of 72 MMcf 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.

Assets

As of December 31, 2008, Gas Operations owned approximately 70,000 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 the 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 2008, CES marketed approximately 528 Bcf of natural gas, transportation and related energy services to approximately 9,700 customers (including approximately 9 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, and are served from offices located in Arkansas, Illinois, Indiana, Louisiana, Minnesota, Missouri, Pennsylvania, Texas and Wisconsin. The business has three operational functions: wholesale, retail and intrastate pipelines, which are further described below.

Wholesale Operations. 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 inter- and intra-state pipeline companies, and include gas utilities, large industrial customers and electric generation customers.

Retail Operations. CES offers a variety of natural gas management services to smaller commercial and industrial customers, municipalities, educational institutions and hospitals, whose facilities are 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 sixteen states.

Intrastate Pipeline Operations. CEIP primarily 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 32 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). In 2008, CES' VaR averaged $1.5 million with a high of $2.8 million.

The CenterPoint Energy risk control policy, governed 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 are consistent with its 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.

Assets

CEIP owns and operates approximately 227 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 1.1 Bcf per day on various inter- and intrastate pipelines and approximately 8.8 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 (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 Corporation (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. Our 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 2008, approximately 15% 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. Effective April 1, 2008, MRT signed a 5-year extension of its firm transportation and storage contracts with Laclede. Agreements for firm transportation, "no notice" transportation service and storage services in certain of Gas Operations' service areas (Arkansas, Louisiana, Oklahoma and Texas) will expire in 2012.

Carthage to Perryville. In April 2008, CEGT completed the Phase III expansion of the Carthage to Perryville pipeline. This expansion included additional compression and authorization from the Pipeline and Hazardous Materials Safety Administration (PHMSA) to operate the line at higher pressures. The Carthage to Perryville pipeline can now operate at up to 1.5 Bcf per day. CEGT filed with FERC on December 5, 2008 to increase the Carthage to Perryville capacity to approximately 1.9 Bcf per day. The expansion includes a new compressor unit at two of CEGT's existing stations and is currently projected to be placed in service in the second quarter of 2010.

Southeast Supply Header. The Southeast Supply Header (SESH) pipeline project, a joint venture between CEGT and Spectra Energy Corp., was placed into commercial service on September 6, 2008. This new 270-mile pipeline, which extends from the Perryville Hub, near Perryville, Louisiana, to an interconnection with the Gulf Stream Natural Gas System near Mobile, Alabama, has a maximum design capacity of approximately one Bcf per day. The pipeline represents a new source of natural gas supply for the Southeast United States and offers greater supply diversity to this region. Our share of SESH's net construction costs is approximately $625 million.

Assets

Our 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. We also own and operate six natural gas storage fields with a combined daily deliverability of approximately 1.2 Bcf and a combined working gas capacity of approximately 59 Bcf. We also own 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. Our 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

Our 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. Our interstate pipelines business competes indirectly with other forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price. 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, Inc. (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 1.3 Bcf per day of natural gas and, either directly or through its 50% interest in a joint venture, processes in excess of 240 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.

Our 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.

Assets

Our field services business owns and operates approximately 3,600 miles of gathering pipelines and processing plants that collect, treat and process natural gas from approximately 150 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Competition

Our 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. Our field services business competes indirectly with other forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price. 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 impacted 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 14 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 intrastate 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.

Our 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 impose fines and other sanctions on Electric Entities that fail to comply with the 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.

Under the Public Utility Holding Company Act of 2005 (PUHCA 2005), the FERC has authority to require holding companies and their subsidiaries to maintain certain books and records and make them available for review by the FERC and state regulatory authorities in certain circumstances. In December 2005, the FERC issued rules implementing PUHCA 2005. Pursuant to those rules, in June 2006, we filed with the FERC the required notification of our status as a public utility holding company. In October 2006, the FERC adopted additional rules regarding maintenance of books and records by utility holding companies and additional reporting and accounting requirements for centralized service companies that make allocations to public utilities regulated by the FERC under the Federal Power Act. Although we provide services to our subsidiaries through a service company, our service company is not subject to the FERC's service company rules.

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 based on amounts of energy delivered, whereas distribution rates for a majority of commercial and industrial customers are based on peak demand. All REPs in CenterPoint Houston's service area pay the same rates and other charges for the same transmission and distribution services. 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. 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 and transition charges associated with securitization of regulatory assets and securitization of stranded costs.

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.

CenterPoint Houston Interim Transmission Costs of Service Update. In September 2008, CenterPoint Houston filed an application with the Texas Utility Commission requesting an interim update to its wholesale transmission rate. The filing resulted in a revenue requirement increase of $22.5 million over rates then in effect. Approximately 74% will be paid by distribution companies other than CenterPoint Houston. The remaining 26% represents CenterPoint Houston's share. That amount cannot be included in rates until 2010 under the terms of the rate freeze implemented in the settlement of CenterPoint Houston's 2006 rate proceeding described below. In November 2008, the Texas Utility Commission approved CenterPoint Houston's request. The interim rates became effective for service on and after November 5, 2008.

CenterPoint Houston Rate Agreement. CenterPoint Houston's transmission and distribution rates are subject to the terms of a Settlement Agreement effective in October 2006. The Settlement Agreement provides that until June 30, 2010 CenterPoint Houston will not seek to increase its base rates and the other parties will not petition to decrease those rates. The rate freeze is subject to adjustment for certain limited matters, including the results of the appeals of the True-Up Order, the implementation of charges associated with securitizations, the impact of severe weather such as hurricanes and certain other force majeure events. CenterPoint Houston must make a new base rate filing not later than June 30, 2010, based on a test year ended December 31, 2009, unless the staff of the Texas Utility Commission and certain cities notify it that such a filing is unnecessary.

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 Gas Operations serves that have retained original jurisdiction.

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. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Texas Coast service territory. Of the 47 cities, 23 either affirmatively approved or allowed the filed rates to go into effect by operation of law. Nine other cities were represented by the Texas Coast Utilities Coalition (TCUC) and 15 cities were represented by the Gulf Coast Coalition of Cities (GCCC). In July 2008, Gas Operations reached a settlement agreement with the GCCC. That settlement agreement, if implemented across the entire Texas Coast service territory, would allow Gas Operations a $3.4 million annual increase in revenues. The TCUC cities denied the rate change request and Gas Operations appealed the denial of rates to the Railroad Commission. The Railroad Commission issued an order in October 2008, which, if implemented across the entire Texas Coast service territory, would result in an annual revenue increase of $3.7 million. Both the Railroad Commission order and the settlement provide for an annual rate adjustment mechanism to reflect changes in operating expenses and revenues as well as changes in capital investment and associated changes in revenue-related taxes. In December 2008, the Railroad Commission issued an order on rehearing. Parties have filed second motions for rehearing on this order. However, in December 2008, Gas Operations implemented the approved rates for the nine TCUC cities and the environs, subject to refund. The impact of the Railroad Commission's order on rehearing on the settled rates is still under review, and how rates will be conformed among all cities in the Texas Coast service territory is unknown at this time. A final decision from the Railroad Commission regarding the second motions for rehearing is expected no later than March 2009.

Minnesota. In November 2006, the Minnesota Public Utilities Commission (MPUC) denied a request filed by Gas Operations for a waiver of MPUC rules in order to allow Gas Operations to recover approximately $21 million in unrecovered purchased gas costs related to periods prior to July 1, 2004. Those unrecovered gas costs were identified as a result of revisions to previously approved calculations of unrecovered purchased gas costs. Following that denial, Gas Operations recorded a $21 million adjustment to reduce pre-tax earnings in the fourth quarter of 2006 and reduced the regulatory asset related to these costs by an equal amount. In March 2007, following the MPUC's denial of reconsideration of its ruling, Gas Operations petitioned the Minnesota Court of Appeals for review of the MPUC's decision, and in May 2008 that court ruled that the MPUC had been arbitrary and capricious in denying Gas Operations a waiver. The court ordered the case remanded to the MPUC for reconsideration under the same principles the MPUC had applied in previously granted waiver requests. The MPUC sought further review of the court of appeals decision from the Minnesota Supreme Court, and in July 2008, the Minnesota Supreme Court agreed to review the decision. In January 2009, the Minnesota Supreme Court heard oral arguments. While there is no deadline for a decision, a decision is expected by the end of the third quarter of 2009. While no prediction can be made as to the ultimate outcome, this matter will have no negative impact on our financial condition, results of operations or cash flows.

In November 2008, Gas Operations filed a request with the MPUC to increase its rates for utility distribution service. If approved by the MPUC, the proposed new rates would result in an overall increase in annual revenue of $59.8 million. The proposed increase would allow Gas Operations to recover increased operating costs, including higher bad debt and collection expenses, the cost of improved customer service and inflationary increases in other expenses. It also would allow recovery of increased costs related to conservation improvement programs and provide a return for the additional capital invested to serve its customers. In addition, Gas Operations is seeking 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. The MPUC is allowed ten months to issue a final decision; however, an extension of time can occur in certain circumstances.

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 legislation, 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 2002 Act, and then the 2006 Act, the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation (DOT) 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.

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. Based on our interpretation of the rules written to date and preliminary technical reviews, we believe compliance will require annual expenditures (capital and operating costs combined) of approximately $17 to 24 million during the initial 10-year period.

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, 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 pollution conditions caused by our operations, or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

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” 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 greenhouse gases 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 industries such as the utility industry to meet stringent new standards requiring substantial reductions in carbon emissions. Those reductions could be costly and difficult to implement. Some proposals would provide for credits to those who reduce emissions below certain levels and would allow those credits to be traded and/or sold to others. While there is growing consensus that some form of global climate change program will be adopted, it is too early to determine when, and in what form, a regulatory scheme regarding greenhouse gas emissions will be adopted or what specific impacts a new regulatory scheme might have on us and our subsidiaries. However, 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 scheme that would reduce consumption of natural gas if ultimately adopted. Our electric transmission and distribution business, unlike most 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 are in the business of generating electricity. Nevertheless, CenterPoint Houston’s revenues could be adversely affected to the extent any resulting regulatory scheme has the effect of reducing consumption of electricity by ultimate consumers within its service territory.

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. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies.

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 United States Environmental Protection Agency (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, 2008, 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. As of December 31, 2008, CERC had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

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 the subject of the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. CERC is investigating details regarding the site and the range of environmental expenditures for potential remediation. However, 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.

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

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 the purchaser. 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 and the court, is expected to finally 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, 2008, we had 8,801 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	2,858	1,236
Natural Gas Distribution	3,652	1,405
Competitive Natural Gas Sales and Services	122	—
Interstate Pipelines	654	—
Field Services	215	—
Other Operations	1,300	—
Total	8,801	2,641

As of December 31, 2008, approximately 30% of our employees are subject to collective bargaining agreements. One of the collective bargaining agreements covering approximately 5% of our employees, Gas Workers Union Local No. 340, is scheduled to expire in 2009. We have a good relationship with this bargaining unit and expect to negotiate a new agreement in 2009.

EXECUTIVE OFFICERS
(as of February 25, 2009)

Name	Age	Title
David M. McClanahan	59	President and Chief Executive Officer and Director
Scott E. Rozzell	59	Executive Vice President, General Counsel and Corporate Secretary
Gary L. Whitlock	59	Executive Vice President and Chief Financial Officer
C. Gregory Harper	44	Senior Vice President and Group President, CenterPoint Energy Pipelines and Field Services
Thomas R. Standish	59	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 the 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 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

CenterPoint Houston may not be successful in ultimately recovering the full value of its true-up components, which could result in the elimination of certain tax benefits and 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 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.

Review by the Texas Supreme Court of the court of appeals decision is at the discretion of the court. In November 2008, the Texas Supreme Court requested the parties to the Petitions for Review to submit briefs on the merits of the issues raised. Briefing at the Texas Supreme Court should be completed in the second quarter of 2009. Although the Texas Supreme Court has not indicated whether it will grant review of the lower court’s decision, its request for full briefing on the merits allowed the parties to more fully explain their positions. There is no prescribed time in which the Texas Supreme Court must determine whether to grant review or, if review is granted, for a decision by that court. 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 and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-Up Order, but could range from $170 million to $385 million (pre-tax) plus interest subsequent to December 31, 2008.

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, for 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. In its opinion, the court of appeals ordered that this issue be remanded to the Texas Utility Commission, as that commission requested. No party, in the petitions for review or briefs filed with the Texas Supreme Court, has challenged that order by the court of appeals, though the Texas Supreme Court, if it grants review, will have 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 or administrative process. Although the Texas Utility Commission 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 must seek recovery of significant restoration costs arising from Hurricane Ike.

CenterPoint Houston's electric delivery system suffered substantial damage as a result of Hurricane Ike, which struck the upper Texas coast on September 13, 2008. CenterPoint Houston estimates that total costs to restore the electric delivery facilities damaged as a result of Hurricane Ike will be in the range of $600 million to $650 million.

CenterPoint Houston believes it is entitled to recover prudently incurred storm costs in accordance with applicable regulatory and legal principles. The Texas Legislature currently is considering passage of legislation that would (i) authorize the Texas Utility Commission to determine the amount of storm restoration costs that CenterPoint Houston would be entitled to recover and (ii) permit the Texas Utility Commission to issue a financing order that would allow CenterPoint Houston to recover the amount of storm restoration costs determined in such a proceeding through issuance of dedicated securitization bonds, which would be repaid over time through a charge imposed on REPs. In proceedings to determine and seek recovery of storm restoration costs under the proposed legislation, CenterPoint Houston would be required to prove to the Texas Utility Commission's satisfaction its prudently incurred costs as well as to demonstrate the cost benefit from using securitization to recover those costs instead of alternative means. Alternatively, CenterPoint Houston has the right to seek recovery of these costs under traditional rate making principles. CenterPoint Houston's failure to recover costs incurred as a result of Hurricane Ike could adversely affect its liquidity, results of operations and financial condition. For more information about CenterPoint Houston's recovery from Hurricane Ike, please read "Business — Electric Transmission & Distribution — Hurricane Ike" in Item 1 of this report.

CenterPoint Houston's receivables are concentrated in a small number of retail electric providers, 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, 2008, CenterPoint Houston did business with 79 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. In 2008, seven REPs selling power within CenterPoint Houston's service territory ceased to operate, and their customers were transferred to the provider of last resort or to other REPs. 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 demand credit protection from REPs for payments not made prior to the shift to the provider of last resort. However, the Texas Utility Commission is currently considering proposed revisions to those regulations that, as currently proposed, would (i) increase the credit protections that could be required from REPs, and (ii) allow utilities to defer the loss of payments for recovery in a future rate case. Whether such revised regulations will ultimately be adopted and their terms cannot now be determined. RRI, through its subsidiaries, is CenterPoint Houston's largest customer. Approximately 46% of CenterPoint Houston's $141 million in billed receivables from REPs at December 31, 2008 was owed by subsidiaries of RRI. Any delay or default in payment by REPs such as RRI could adversely affect CenterPoint Houston's cash flows, financial condition and results of operations. RRI's unsecured debt ratings are currently below investment grade. If RRI were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event RRI's subsidiaries might seek to avoid honoring their obligations and claims might be made by creditors involving payments CenterPoint Houston has received from RRI's subsidiaries.

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.

In this regard, pursuant to the Stipulation and Settlement Agreement approved by the Texas Utility Commission in September 2006, until June 30, 2010 CenterPoint Houston is limited in its ability to request retail rate relief. For more information on the Stipulation and Settlement Agreement, please read "Business — Regulation — State and Local Regulation — Electric Transmission & Distribution — CenterPoint Houston Rate Agreement" in Item 1 of this report.

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. 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 increases 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 volumes and revenues and (ii) increase the risk that CERC's suppliers or customers fail or are unable to meet their obligations. Additionally, increasing natural gas prices could create the need for CERC to provide collateral in order to purchase natural gas.

A decline in CERC's credit rating could result in CERC's having to provide collateral in order to purchase gas.

If CERC's credit rating were to decline, it might be required to post cash collateral 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.

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, the ability of producers to obtain necessary drilling and other governmental permits, access to drilling rigs and regulatory changes. 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 (NGL). 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 under construction and related compression facilities may be significantly higher than CERC had planned.

Subsidiaries of CERC Corp. have been recently involved in significant pipeline construction projects and, depending on available opportunities, may, from time to time, be involved in additional significant pipeline construction projects in the future. The construction of new pipelines and related compression facilities requires 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 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 Act, 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, some states in which CERC does business have sought to expand their own regulatory frameworks to give their 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 businesses 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 operate its utility operations, to finance its business and to provide cost-effective utility service. In addition, if more than one state adopts restrictions over 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, 2008, we had $10.7 billion of outstanding indebtedness on a consolidated basis, which includes $2.6 billion of non-recourse transition bonds. As of December 31, 2008, approximately $953 million principal amount of this debt is required to be paid through 2011. This amount excludes principal repayments of approximately $669 million on transition 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 components, including, in particular, the results of appeals to the courts regarding rulings obtained to date;
- CenterPoint Houston's recovery of costs arising from Hurricane Ike;
- 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 RRI in connection with its indemnification obligations arising in connection with its separation from us; and
- provisions of relevant tax and securities laws.

As of December 31, 2008, CenterPoint Houston had outstanding approximately $2.6 billion aggregate principal amount of general mortgage bonds, including approximately $527 million held in trust to secure pollution control bonds for which we are obligated, $600 million securing borrowings under a credit facility which was unutilized and approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had outstanding approximately $253 million aggregate principal amount of first mortgage bonds, 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 $1.8 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, 2008. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions. In January 2009, CenterPoint Houston issued $500 million aggregate principal amount of general mortgage bonds in a public offering.

Our current credit ratings are discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations of CenterPoint Energy, Inc. and Subsidiaries — Liquidity and Capital Resources — Future Sources and Uses of Cash — Impact on Liquidity of a Downgrade in Credit Ratings" in Item 7 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 described in "Business — Environmental Matters" in Item 1 of this Form 10-K. 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 pollution conditions caused by our operations, or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

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 because CenterPoint Houston believes it to be cost prohibitive. CenterPoint Houston may not be able to recover the costs incurred in restoring its transmission and distribution properties following Hurricane Ike, or any such costs sustained in the future, through a change in its regulated rates, and 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, RRI 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 RRI 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.

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. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for CERC's benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, we, CERC and RRI amended that agreement and CERC released the letters of credit it held as security. Under the revised agreement, RRI agreed to provide cash or new letters of credit to secure CERC against exposure under the remaining guaranties as calculated under the revised agreement if and to the extent changes in market conditions exposed CERC to a risk of loss on those guaranties.

The potential exposure to CERC under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under these transportation contracts, which will be effective until 2018, was approximately $108 million as of December 31, 2008. RRI continues to meet its obligations under the contracts, and on the basis of market conditions, we and CERC have not required additional security. However, if RRI should fail to perform its obligations under the contracts or if RRI should fail to provide adequate security in the event market conditions change adversely, we would retain our exposure to the counterparty under the guaranty.

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

Reliant Energy and RRI are named as defendants in a number of lawsuits arising out of energy sales in California and other markets and financial reporting matters. Although these matters relate to the business and operations of RRI, claims against Reliant Energy have been made on grounds that include the effect of RRI's financial results on Reliant Energy's historical financial statements and liability of Reliant Energy as a controlling shareholder of RRI. 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 RRI were determined to be unavailable or if RRI were unable to satisfy indemnification obligations owed with respect to those claims.

In connection with the organization and capitalization of Texas Genco, 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. In connection with the sale of Texas Genco's fossil generation assets (coal, lignite and gas-fired plants) to NRG Texas LP (previously named Texas Genco LLC), the separation agreement we entered into with Texas Genco in connection with the organization and capitalization of Texas Genco was amended to provide that all of Texas Genco's rights and obligations under the separation agreement relating to its fossil generation assets, including Texas Genco's obligation to indemnify us with respect to liabilities associated with the fossil generation assets and related business, were assigned to and assumed by NRG Texas LP. In addition, under the amended separation agreement, Texas Genco is no longer liable for, and we have assumed and agreed to indemnify NRG Texas LP 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 or other similar agreements held by us. If Texas Genco or NRG Texas LP were unable to satisfy a liability that had been so assumed or indemnified against, and provided Reliant Energy had not been released from the liability in connection with the transfer, CenterPoint Houston could be responsible for satisfying the liability.

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. Most claimants in such litigation have been workers who participated in construction of various industrial facilities, including power plants. Some of the claimants have worked at locations owned by us, but most existing claims relate to facilities previously owned by us or 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 global financial crisis may have impacts on our business, liquidity and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business, liquidity and our 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. With respect to our existing debt arrangements, Lehman Brothers Bank, FSB, which had an approximately four percent participation in our credit facility and each of the then-existing credit facilities of our subsidiaries, stopped funding its commitments following the bankruptcy filing of its parent in September 2008 and was subsequently terminated as a lender in our facility and the facility of CenterPoint Houston. Defaults of other lenders should they occur could adversely affect our liquidity. Capital market turmoil was also reflected in significant reductions in equity market valuations in 2008, which significantly reduced the value of assets of our pension plan. These reductions are expected to result in increased non-cash pension expense in 2009, which will impact 2009 results of operations.

In addition to the credit and financial market issues, the 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.

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 is 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, which 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 3 and 10(d) to our consolidated financial statements, which information is incorporated herein by reference.

Item 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to the vote of our security holders during the fourth quarter of 2008.

PART II

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

As of February 13, 2009, our common stock was held of record by approximately 47,327 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	
2007			
First Quarter			$ 0.17
January 18		$ 16.51	
February 26	$ 18.37		
Second Quarter			$ 0.17
May 9	$ 20.02		
June 22		$ 16.90	
Third Quarter			$ 0.17
July 13	$ 17.88		
August 15		$ 15.15	
Fourth Quarter			$ 0.17
October 19		$ 15.97	
November 8	$ 18.51		
2008			
First Quarter			$ 0.1825
January 9	$ 16.98		
March 17		$ 13.84	
Second Quarter			$ 0.1825
April 1		$ 14.66	
May 29	$ 17.16		
Third Quarter			$ 0.1825
August 11	$ 16.59		
September 18		$ 13.98	
Fourth Quarter			$ 0.1825
October 1	$ 14.40		
October 10		$ 9.08	

The closing market price of our common stock on December 31, 2008 was $12.62 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 22, 2009, we announced a regular quarterly cash dividend of $0.19 per share, payable on March 10, 2009 to shareholders of record on February 16, 2009.

Repurchases of Equity Securities

During the quarter ended December 31, 2008, 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,				
	2004(1)	2005(2)	2006	2007	2008
	(In millions, except per share amounts)				
Revenues	$ 7,999	$ 9,722	$ 9,319	$ 9,623	$ 11,322
Income from continuing operations before extraordinary item	205	225	432	399	447
Discontinued operations, net of tax	(133)	(3)	—	—	—
Extraordinary item, net of tax	(977)	30	—	—	—
Net income (loss)	$ (905)	$ 252	$ 432	$ 399	$ 447
Basic earnings (loss) per common share:					
Income from continuing operations before extraordinary item	$ 0.67	$ 0.72	$ 1.39	$ 1.25	$ 1.33
Discontinued operations, net of tax	(0.43)	(0.01)	—	—	—
Extraordinary item, net of tax	(3.18)	0.10	—	—	—
Basic earnings (loss) per common share	$ (2.94)	$ 0.81	$ 1.39	$ 1.25	$ 1.33
Diluted earnings (loss) per common share:					
Income from continuing operations before extraordinary item	$ 0.61	$ 0.67	$ 1.33	$ 1.17	$ 1.30
Discontinued operations, net of tax	(0.37)	(0.01)	—	—	—
Extraordinary item, net of tax	(2.72)	0.09	—	—	—
Diluted earnings (loss) per common share	$ (2.48)	$ 0.75	$ 1.33	$ 1.17	$ 1.30
Cash dividends paid per common share	$ 0.40	$ 0.40	$ 0.60	$ 0.68	$ 0.73
Dividend payout ratio from continuing operations	60%	56%	43%	54%	55%
Return from continuing operations on average common equity	14.4%	18.7%	30.3%	23.7%	23.2%
Ratio of earnings from continuing operations to fixed charges	1.43	1.51	1.77	1.86	2.09
At year-end:					
Book value per common share	$ 3.59	$ 4.18	$ 4.96	$ 5.61	$ 5.89
Market price per common share	11.30	12.85	16.58	17.13	12.62
Market price as a percent of book value	315%	307%	334%	305%	214%
Assets of discontinued operations	$ 1,565	$ —	$ —	$ —	$ —
Total assets	18,096	17,116	17,633	17,872	19,676
Short-term borrowings (3)	—	—	187	232	153
Transition bonds, including current maturities	676	2,480	2,407	2,260	2,589
Other long-term debt, including current maturities	8,353	6,427	6,593	7,419	7,925
Capitalization:					
Common stock equity	11%	13%	15%	16%	16%
Long-term debt, including current maturities	89%	87%	85%	84%	84%
Capitalization, excluding transition bonds:					
Common stock equity	12%	17%	19%	20%	20%
Long-term debt, excluding transition bonds, including current maturities	88%	83%	81%	80%	80%
Capital expenditures, excluding discontinued operations	$ 530	$ 719	$ 1,121	$ 1,011	$ 1,053

(1) Net income for 2004 includes an after-tax extraordinary loss of $977 million ($3.18 and $2.72 loss per basic and diluted share, respectively) based on our analysis of the Public Utility Commission of Texas' (Texas Utility Commission) order in the 2004 True-Up Proceeding. Additionally, we recorded as discontinued operations a net after-tax loss of approximately $133 million ($0.43 and $0.37 loss per basic and diluted share, respectively) in 2004 related to our interest in Texas Genco.

(2) Net income for 2005 includes an after-tax extraordinary gain of $30 million ($0.10 and $0.09 per basic and diluted share, respectively) recorded in the first quarter reflecting an adjustment to the extraordinary loss recorded in the last half of 2004 to write down generation-related regulatory assets as a result of the final orders issued by the Texas Utility Commission.

(3) Under the terms of the receivables facilities in place since October 2006, the provisions for sale accounting under Statement of Financial Accounting Standards No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," have not been met. Accordingly, advances received upon the sale of receivables are accounted for as short-term borrowings as of December 31, 2006, 2007 and 2008. As of December 31, 2008, short-term borrowings included a $75 million inventory financing obligation related to an asset management agreement. For more information regarding this transaction, see Note 8(a).

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 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, 2008 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 over 2 million metered customers in a 5,000-square-mile area of the Texas Gulf Coast that has a population of approximately 5.6 million people and includes 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 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 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 3.2 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 the six states listed above as well as several other Midwestern and Eastern 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 1.2 billion cubic feet (Bcf) and a combined working gas capacity of approximately 59 Bcf. It 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. Its storage capacity in the Bistineau facility is 8 Bcf of working gas with 100 million cubic feet per day of deliverability. Most storage operations are in north Louisiana and Oklahoma.

Field Services

CERC's field services business owns and operates approximately 3,600 miles of gathering pipelines and processing plants that collect, treat and process natural gas from approximately 150 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

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

Significant Events in 2008 and 2009

Hurricane Ike

CenterPoint Houston's electric delivery system suffered substantial damage as a result of Hurricane Ike, which struck the upper Texas coast early Saturday, September 13, 2008.

The strong Category 2 storm initially left more than 90% of CenterPoint Houston's more than 2 million metered customers without power, the largest outage in CenterPoint Houston's 130-year history. Most of the widespread power outages were due to power lines damaged by downed trees and debris blown by Hurricane Ike's winds. In addition, on Galveston Island and along the coastal areas of the Gulf of Mexico and Galveston Bay, the storm surge and flooding from rains accompanying the storm caused significant damage or destruction of houses and businesses served by CenterPoint Houston.

CenterPoint Houston estimates that total costs to restore the electric delivery facilities damaged as a result of Hurricane Ike will be in the range of $600 million to $650 million. As is common with electric utilities serving coastal regions, the poles, towers, wires, street lights and pole mounted equipment that comprise CenterPoint Houston's transmission and distribution system are not covered by property insurance, but office buildings and warehouses and their contents and substations are covered by insurance that provides for a maximum deductible of $10 million. Current estimates are that total losses to property covered by this insurance were approximately $17 million.

In addition to storm restoration costs, CenterPoint Houston lost approximately $17 million in revenue through December 31, 2008. Within the first 18 days after the storm, CenterPoint Houston had restored power to all customers capable of receiving it.

CenterPoint Houston has deferred the uninsured storm restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. As a result, storm restoration costs did not affect our or CenterPoint Houston's reported net income for 2008. As of December 31, 2008, CenterPoint Houston recorded an increase of $145 million in construction work in progress and $435 million in regulatory assets for restoration costs incurred through December 31, 2008. Approximately $73 million of these costs are based on estimates and are included in accounts payable as of December 31, 2008. Additional restoration costs will continue to be incurred in 2009.

Assuming necessary enabling legislation is enacted by the Texas Legislature in the session that began in January 2009, CenterPoint Houston expects to seek a financing order from the Texas Utility Commission to obtain recovery of its storm restoration costs through the issuance of non-recourse securitization bonds similar to the storm recovery bonds issued by another Texas utility following the hurricanes that affected that utility's service territories in 2005. Assuming those bonds are issued, CenterPoint Houston will recover the amount of storm restoration costs determined by the Texas Utility Commission to have been prudently incurred out of the bond proceeds, with the bonds being repaid over time through a charge imposed on customers. Alternatively, if securitization is not available, recovery of those costs would be sought through traditional regulatory mechanisms. Under its 2006 rate case settlement, CenterPoint Houston is entitled to seek an adjustment to rates in this situation, even though in most instances its rates are frozen until 2010.

Gas Operations also suffered some damage to its system in Houston, Texas and in other portions of its service territory across Texas and Louisiana. As of December 31, 2008, Gas Operations has deferred approximately $4 million of costs related to Hurricane Ike for recovery as part of future natural gas distribution rate proceedings.

Debt Financing Transactions

Pursuant to a financing order issued by the Texas Utility Commission in September 2007, in February 2008 a subsidiary of CenterPoint Houston issued approximately $488 million in transition bonds in two tranches with interest rates of 4.192% and 5.234% and final maturity dates in February 2020 and February 2023, respectively. Scheduled final payment dates are February 2017 and February 2020. Through issuance of the transition bonds, CenterPoint Houston securitized transition property of approximately $483 million representing the remaining balance of the competition transition charge (CTC) adjusted to refund certain unspent environmental retrofit costs and to recover the amount of the fuel reconciliation settlement.

In April 2008, we purchased $175 million principal amount of pollution control bonds issued on our behalf at 102% of their principal amount. Prior to the purchase, $100 million principal amount of such bonds had a fixed rate of interest of 7.75% and $75 million principal amount of such bonds had a fixed rate of interest of 8%. Depending on market conditions, we may remarket both series of bonds, at 100% of their principal amounts, in 2009.

In April 2008, we called our 3.75% convertible senior notes for redemption on May 30, 2008. At the time of the announcement, the notes were convertible at the option of the holders, and substantially all of the notes were submitted for conversion on or prior to the May 30, 2008 redemption date. During the year ended December 31, 2008, we issued 16.9 million shares of our common stock and paid cash of approximately $532 million to settle conversions of approximately $535 million principal amount of our 3.75% convertible senior notes.

In May 2008, we issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.50%. The proceeds from the sale of the senior notes were used for general corporate purposes, including the satisfaction of cash payment obligations in connection with conversions of our 3.75% convertible senior notes as discussed above.

In May 2008, CERC Corp. issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.00%. The proceeds from the sale of the senior notes were used for general corporate purposes, including capital expenditures, working capital and loans to or investments in affiliates.

In November 2008, CERC replaced a receivables facility that had expired in October 2008 with a new receivables facility that expires in November 2009. Availability under the new facility ranges from $128 million to $375 million, reflecting seasonal changes in receivables balances.

In November 2008, CenterPoint Houston entered into a $600 million 364-day credit facility. The credit facility will terminate if bonds are issued to securitize the costs incurred as a result of Hurricane Ike and if those bonds are issued prior to the November 24, 2009 expiration of the facility. CenterPoint Houston expects to seek legislative and regulatory approval for the issuance of such bonds during 2009.

In December 2008, CERC entered into an asset management agreement whereby it sold $110 million of its natural gas in storage and agreed to repurchase an equivalent amount of natural gas during the 2008-2009 winter heating season for payments totaling $114 million. This transaction was accounted for as a financing and, as of December 31, 2008, the consolidated financial statements reflect natural gas inventory of $75 million and a financing obligation of $75 million related to this transaction.

In January 2009, CenterPoint Houston issued $500 million aggregate principal amount of general mortgage bonds due in March 2014 with an interest rate of 7.00%. The proceeds from the sale of the bonds were used for general corporate purposes, including the repayment of outstanding borrowings under its revolving credit facility and the money pool, capital expenditures and storm restoration costs associated with Hurricane Ike.

Equity Financing Transactions

In 2008, we received proceeds of approximately $65 million from the sale of approximately 4.9 million common shares to our defined contribution plan and proceeds of approximately $13 million from the sale of approximately 0.9 million common shares to participants in our enhanced dividend reinvestment plan.

Interstate Pipeline Expansion

The Southeast Supply Header (SESH) pipeline project, a joint venture between CenterPoint Energy Gas Transmission, a wholly owned subsidiary of CERC Corp., and Spectra Energy Corp., was placed into commercial service on September 6, 2008. This new 270-mile pipeline, which extends from the Perryville Hub, near Perryville, Louisiana, to an interconnection with the Gulf Stream Natural Gas System near Mobile, Alabama, has a maximum design capacity of approximately one Bcf per day. The pipeline represents a new source of natural gas supply for the Southeast United States and offers greater supply diversity to this region. Our share of SESH's net construction costs is approximately $625 million.

Outlook

During 2008, economic conditions in the United States declined significantly, with several large bank failures and consolidations, large declines in the values of securities, disruptions in the capital markets, which made it difficult to raise debt and equity, and increased costs for capital when it was available. Many of the factors that led to the economic decline are continuing into 2009, but it is impossible to predict the impacts such events may have in the future. Although our businesses and the areas in which we serve have, to date, not been as significantly affected as some others, in 2008, we experienced substantial declines in the value of our pension plan assets as a result of the stock market declines. Disruptions in the bank and capital markets during the last two quarters of 2008 have led to higher borrowing costs and greater uncertainty regarding the ability to execute transactions in these markets.

Although we cannot predict future performance, the decline in the value of our pension plan assets that occurred during 2008 will result in increased non-cash charges to pension plan expense in 2009, which will adversely impact earnings, and may also result in the need for us to make significant cash contributions to our pension plan subsequent to 2009. We also expect to experience higher borrowing costs and greater uncertainty in executing capital markets transactions if conditions in financial markets do not improve from their current state.

To the extent the adverse economic conditions affect our suppliers and customers, results from our energy delivery businesses may suffer. The current low commodity prices for natural gas and other energy products may cause energy producers to scale back projects such as drilling new gas wells or constructing new facilities. 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.

These factors may lead to reduced earnings during 2009, compared to 2008, if they continue significantly into 2009 or if the magnitude of the economic downturn increases beyond the impacts experienced in 2008.

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 components, including, in particular, the results of appeals to the courts regarding rulings obtained to date;
- state and federal legislative and regulatory actions or developments, including deregulation, re-regulation, environmental regulations, including regulations related to global climate change, and changes in or application of laws or regulations applicable to the various aspects of our business;
- timely and appropriate legislative and regulatory actions allowing securitization or other recovery of costs associated with Hurricane Ike;
- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;
- cost overruns on major capital projects that cannot be recouped in prices;
- industrial, commercial and residential growth in our service territory and changes in market demand and demographic patterns;
- the timing and extent of changes in commodity prices, particularly natural gas and natural gas liquids;
- the timing and extent of changes in the supply of natural gas;
- the timing and extent of changes in natural gas basis differentials;
- weather variations and other natural phenomena;
- 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, including Reliant Energy, Inc. (RRI);
- the ability of RRI and its subsidiaries to satisfy their other obligations to us, including indemnity obligations, or in connection with the contractual arrangements pursuant to which we are their guarantor;
- the outcome of litigation brought by or against us;
- our ability to control costs;
- the investment performance of our employee benefit plans;
- our potential business strategies, including 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,		
	2006	2007	2008
Revenues	$ 9,319	$ 9,623	$ 11,322
Expenses	8,274	8,438	10,049
Operating Income	1,045	1,185	1,273
Gain (Loss) on Time Warner Investment	94	(114)	(139)
Gain (Loss) on Indexed Debt Securities	(80)	111	128
Interest and Other Finance Charges	(470)	(503)	(466)
Interest on Transition Bonds	(130)	(123)	(136)
Distribution from AOL Time Warner Litigation Settlement	—	32	—
Additional Distribution to ZENS Holders	—	(27)	—
Equity in Earnings of Unconsolidated Affiliates	6	16	51
Other Income, net	29	17	14
Income Before Income Taxes	494	594	725
Income Tax Expense	(62)	(195)	(278)
Net Income	$ 432	$ 399	$ 447
Basic Earnings Per Share	$ 1.39	$ 1.25	$ 1.33
Diluted Earnings Per Share	$ 1.33	$ 1.17	$ 1.30

2008 Compared to 2007

Net Income. We reported net income of $447 million ($1.30 per diluted share) for 2008 compared to $399 million ($1.17 per diluted share) for the same period in 2007. The increase in net income of $48 million was primarily due to an $88 million increase in operating income, a $37 million decrease in interest expense, excluding transition bond-related interest expense, a $35 million increase in equity in earnings of unconsolidated affiliates related primarily to SESH and a $17 million increase in the gain on our indexed debt securities. These increases in net income were partially offset by an $83 million increase in income tax expense, a $25 million increase in the loss on our Time Warner investment and a $13 million increase in interest expense on transition bonds.

Income Tax Expense. Our 2008 effective tax rate of 38.4% differed from the 2007 effective tax rate of 32.8% primarily as a result of revisions to the Texas State Franchise Tax Law (Texas margin tax) which was reported as an operating expense prior to 2008 and is now being reported as an income tax for CenterPoint Houston and a Texas state tax examination in 2007.

2007 Compared to 2006

Net Income. We reported net income of $399 million ($1.17 per diluted share) for 2007 compared to $432 million ($1.33 per diluted share) for the same period in 2006. The decrease in net income of $33 million was primarily due to a $208 million increase in the loss on our Time Warner investment, a $133 million increase in income tax expense primarily as a result of the favorable tax settlement reached with the Internal Revenue Service (IRS) in 2006 related to our 2.0% Zero Premium Exchangeable Subordinated Notes due 2029 (ZENS) and Automatic Common Exchange Securities (ACES) and a $33 million increase in interest expense, excluding transition bond-related interest expense, due to higher borrowing levels. These decreases in net income were partially offset by a $191 million increase in the gain on our indexed debt securities, a $140 million increase in operating income and a $10 million increase in equity in earnings of unconsolidated affiliates.

Income Tax Expense. In 2007, our effective tax rate of 32.8% was lower than the expected statutory tax rate as a result of the revised Texas margin tax and a Texas state tax examination for tax years 2002 through 2004. Our 2007 effective tax rate differed from the 2006 effective tax rate of 12.6% primarily due to the favorable tax settlement reached with the IRS in 2006 as discussed above.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for 2006, 2007 and 2008. 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 (Loss) by Business Segment

	Year Ended December 31,		
	2006	2007	2008
Electric Transmission & Distribution	$ 576	$ 561	$ 545
Natural Gas Distribution	124	218	215
Competitive Natural Gas Sales and Services	77	75	62
Interstate Pipelines	181	237	293
Field Services	89	99	147
Other Operations	(2)	(5)	11
Total Consolidated Operating Income	$ 1,045	$ 1,185	$ 1,273

Electric Transmission & Distribution

The following tables provide summary data of our Electric Transmission & Distribution business segment, CenterPoint Houston, for 2006, 2007 and 2008 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2006	2007	2008
Revenues:			
Electric transmission and distribution utility	$ 1,516	$ 1,560	$ 1,593
Transition bond companies	265	277	323
Total revenues	1,781	1,837	1,916
Expenses:			
Operation and maintenance, excluding transition bond companies	611	652	703
Depreciation and amortization, excluding transition bond companies	243	243	277
Taxes other than income taxes	212	223	201
Transition bond companies	139	158	190
Total expenses	1,205	1,276	1,371
Operating Income	$ 576	$ 561	$ 545
Operating Income:			
Electric transmission and distribution operations	$ 395	$ 400	$ 407
Competition transition charge	55	42	5
Transition bond companies (1)	126	119	133
Total segment operating income	$ 576	$ 561	$ 545
Throughput (in gigawatt-hours (GWh)):			
Residential	23,955	23,999	24,258
Total	75,877	76,291	74,840
Number of metered customers at period end:			
Residential	1,743,963	1,793,600	1,821,267
Total	1,980,960	2,034,074	2,064,854

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

2008 Compared to 2007. Our Electric Transmission & Distribution business segment reported operating income of $545 million for 2008, consisting of $407 million from our regulated electric transmission and distribution utility operations (TDU), exclusive of an additional $5 million from the competition transition charge (CTC), and $133 million related to transition bond companies. For 2007, operating income totaled $561 million, consisting of $400 million from the TDU, exclusive of an additional $42 million from the CTC, and $119 million related to transition bond companies. Revenues for the TDU increased due to customer growth, with over 30,000 metered customers added in 2008 ($23 million), increased usage ($15 million) in part caused by favorable weather experienced in 2008, increased transmission-related revenues ($21 million) and increased revenues from ancillary services ($5 million), partially offset by reduced revenues due to Hurricane Ike ($17 million) and the settlement of the final fuel reconciliation in 2007 ($5 million). Operation and maintenance expense increased primarily due to higher transmission costs ($43 million), the settlement of the final fuel reconciliation in 2007 ($13 million) and increased support services ($13 million), partially offset by a gain on sale of land ($9 million) and normal operating and maintenance expenses that were postponed as a result of Hurricane Ike restoration efforts ($10 million). Depreciation and amortization increased $34 million primarily due to amounts related to the CTC ($30 million), which were offset by similar amounts in revenues. Taxes other than income taxes declined $21 million primarily as a result of the Texas margin tax being classified as an income tax for financial reporting purposes in 2008 ($19 million) and a refund of prior years' state franchise taxes ($5 million).

2007 Compared to 2006. Our Electric Transmission & Distribution business segment reported operating income of $561 million for 2007, consisting of $400 million from the TDU, exclusive of an additional $42 million from the CTC, and $119 million related to transition bond companies. For 2006, operating income totaled $576 million, consisting of $395 million from the TDU, exclusive of an additional $55 million from the CTC, and $126 million related to transition bond companies. Revenues increased due to growth ($22 million), with over 53,000 metered customers added in 2007, higher transmission-related revenues ($22 million), increased miscellaneous service charges ($15 million), increased demand ($7 million), interest on settlement of the final fuel reconciliation ($4 million) and a one-time charge in the second quarter of 2006 related to the resolution of the unbundled cost of service order ($32 million). These increases were partially offset by the rate reduction resulting from the 2006 rate case settlement that was implemented in October 2006 ($41 million) and lower CTC return resulting from the reduction in the allowed interest rate on the unrecovered CTC balance from 11.07% to 8.06% in 2006 ($13 million). Operation and maintenance expense increased primarily due to higher transmission costs ($25 million), the absence of a gain on the sale of property in 2006 ($13 million), and increased expenses, primarily related to low income and energy efficiency programs as required by the 2006 rate case settlement ($8 million), partially offset by settlement of the final fuel reconciliation ($13 million).

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2006, 2007 and 2008 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2006	2007	2008
Revenues	$ 3,593	$ 3,759	$ 4,226
Expenses:			
Natural gas	2,598	2,683	3,124
Operation and maintenance	594	579	589
Depreciation and amortization	152	155	157
Taxes other than income taxes	125	124	141
Total expenses	3,469	3,541	4,011
Operating Income	$ 124	$ 218	$ 215
Throughput (in Bcf):			
Residential	152	172	175
Commercial and industrial	224	232	236
Total Throughput	376	404	411
Number of customers at period end:			
Residential	2,926,483	2,961,110	2,987,222
Commercial and industrial	246,351	249,877	248,476
Total	3,172,834	3,210,987	3,235,698

2008 Compared to 2007. Our Natural Gas Distribution business segment reported operating income of $215 million for 2008 compared to $218 million for 2007. Operating income declined due to a combination of non-weather-related usage ($13 million), due in part to higher gas prices, higher customer-related and support services costs ($9 million), higher bad debts and collection costs ($4 million), increased costs of materials and supplies ($4 million), and an increase in depreciation and amortization and taxes other than income taxes ($3 million) resulting from increased investment in property, plant and equipment. The adverse impacts on operating income were partially offset by the net impact of rate increases ($11 million), lower labor and benefits costs ($14 million), and customer growth from the addition of approximately 25,000 customers in 2008 ($6 million).

2007 Compared to 2006. Our Natural Gas Distribution business segment reported operating income of $218 million for 2007 compared to $124 million for 2006. Operating income improved as a result of increased usage primarily due to a return to more normal weather in 2007 compared to the unusually mild weather in 2006 ($33 million), growth from the addition of over 38,000 customers in 2007 ($9 million), the effect of the 2006 purchased gas cost write-off ($21 million), the effect of rate changes ($7 million) and reduced operation and maintenance expenses ($15 million). Operation and maintenance expenses declined primarily as a result of costs associated with staff reductions incurred in 2006 ($17 million) and settlement of certain rate case-related items ($9 million), partially offset by increases in bad debts and collection costs ($8 million) and other services ($5 million).

Competitive Natural Gas Sales and Services

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for 2006, 2007 and 2008 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2006	**2007**	**2008**
Revenues	$ 3,651	$ 3,579	$ 4,528
Expenses:			
Natural gas	3,540	3,467	4,423
Operation and maintenance	30	31	39
Depreciation and amortization	1	5	3
Taxes other than income taxes	3	1	1
Total expenses	3,574	3,504	4,466
Operating Income	$ 77	$ 75	$ 62
Throughput (in Bcf)	555	522	528
Number of customers at period end	7,024	7,139	9,771

2008 Compared to 2007. Our Competitive Natural Gas Sales and Services business segment reported operating income of $62 million for the year ended December 31, 2008 compared to $75 million for the year ended December 31, 2007. The decrease in operating income of $13 million primarily resulted from lower gains on sales of gas from previously written down inventory ($24 million) and higher operation and maintenance costs ($6 million), which were partially offset by improved margin as basis and summer/winter spreads increased ($12 million). In addition, 2008 included a gain from mark-to-market accounting ($13 million) and a write-down of natural gas inventory to the lower of average cost or market ($30 million), compared to a charge to income from mark-to-market accounting for non-trading derivatives ($10 million) and a write-down of natural gas inventory to the lower of average cost or market ($11 million) for 2007. 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.

2007 Compared to 2006. Our Competitive Natural Gas Sales and Services business segment reported operating income of $75 million for 2007 compared to $77 million for 2006. The decrease in operating income of $2 million was primarily due to reduced opportunities for optimization of pipeline and storage assets resulting from lower locational and seasonal natural gas price differentials in the wholesale business ($10 million) offset by an increase in sales to commercial and industrial customers in the retail business ($3 million). In addition, 2007 included a charge to income from mark-to-market accounting for non-trading derivatives ($10 million) and a write-down of natural gas inventory to the lower of average cost or market ($11 million), compared to a gain from mark-to-market accounting ($37 million) and an inventory write-down ($66 million) for 2006.

Interstate Pipelines

The following table provides summary data of our Interstate Pipelines business segment for 2006, 2007 and 2008 (in millions, except throughput data):

	Year Ended December 31,		
	2006	2007	2008
Revenues	$ 388	$ 500	$ 650
Expenses:			
Natural gas	31	83	155
Operation and maintenance	120	125	133
Depreciation and amortization	37	44	46
Taxes other than income taxes	19	11	23
Total expenses	207	263	357
Operating Income	$ 181	$ 237	$ 293
Transportation throughput (in Bcf)	939	1,216	1,538

2008 Compared to 2007. Our Interstate Pipeline business segment reported operating income of $293 million for 2008 compared to $237 million for 2007. The increase in operating income was primarily driven by increased margins (revenues less natural gas costs) on the Carthage to Perryville pipeline that went into service in May 2007 ($51 million), increased transportation and ancillary services ($27 million), and a gain on the sale of two storage development projects ($18 million). These increases are partially offset by higher operation and maintenance expenses ($19 million), a write-down associated with pipeline assets removed from service ($7 million), increased depreciation expense ($2 million), and higher taxes other than income taxes ($12 million), largely due to tax refunds in 2007.

2007 Compared to 2006. Our Interstate Pipeline business segment reported operating income of $237 million for 2007 compared to $181 million for 2006. The increase in operating income of $56 million was driven primarily by the new Carthage to Perryville pipeline ($42 million), other transportation and ancillary services ($20 million), lower spending in 2007 on project development costs ($6 million) and a decrease in other taxes ($8 million) related to the settlement of certain state tax issues. These favorable variances to operating income were partially offset by lower sales in 2007 of excess gas associated with storage enhancement projects ($15 million) and increased operating expenses ($6 million).

Equity Earnings. In addition, this business segment recorded equity income of $6 million and $36 million (including $6 million and $33 million of pre-operating allowance for funds used during construction) in the years ended December 31, 2007 and 2008, respectively, from its 50 percent interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption.

Field Services

The following table provides summary data of our Field Services business segment for 2006, 2007 and 2008 (in millions, except throughput data):

	Year Ended December 31,		
	2006	2007	2008
Revenues	$ 150	$ 175	$ 252
Expenses:			
Natural gas	(10)	(4)	21
Operation and maintenance	59	66	69
Depreciation and amortization	10	11	12
Taxes other than income taxes	2	3	3
Total expenses	61	76	105
Operating Income	$ 89	$ 99	$ 147
Gathering throughput (in Bcf)	375	398	421

2008 Compared to 2007. Our Field Services business segment reported operating income of $147 million for 2008 compared to $99 million for 2007. The increase in operating income of $48 million resulted from higher margins (revenue less natural gas costs) from gas gathering, ancillary services and higher commodity prices ($34 million) and a one-time gain related to a settlement and contract buyout of one of our customers ($11 million). Operating expenses increased from 2007 to 2008 due to higher expenses associated with new assets and general cost increases, partially offset by a gain related to the sale of assets in 2008 ($7 million).

2007 Compared to 2006. Our Field Services business segment reported operating income of $99 million for 2007 compared to $89 million for 2006. Continued increased demand for gas gathering and ancillary services ($27 million) was partially offset by lower commodity prices ($10 million) and increased operation and maintenance expenses related to cost increases and expanded operations ($7 million).

Equity Earnings. In addition, this business segment recorded equity income of $6 million, $10 million and $15 million for the years ended December 31, 2006, 2007 and 2008, respectively, from its 50 percent interest in a jointly-owned gas processing plant. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption.

Other Operations

The following table provides summary data for our Other Operations business segment for 2006, 2007 and 2008 (in millions):

	Year Ended December 31,		
	2006	2007	2008
Revenues	$ 15	$ 10	$ 11
Expenses	17	15	–
Operating Income (Loss)	$ (2)	$ (5)	$ 11

2008 Compared to 2007. Our Other Operations business segment's operating income in 2008 compared to 2007 increased by $16 million primarily as a result of a decrease in franchise taxes ($7 million) and a decrease in benefits accruals ($4 million).

2007 Compared to 2006. Our Other Operations business segment's operating loss in 2007 compared to 2006 increased by $3 million.

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flow

The net cash provided by (used in) operating, investing and financing activities for 2006, 2007 and 2008 is as follows (in millions):

	Year Ended December 31,		
	2006	2007	2008
Cash provided by (used in):			
Operating activities	$ 991	$ 774	$ 851
Investing activities	(1,056)	(1,300)	(1,368)
Financing activities	118	528	555

Cash Provided by Operating Activities

Net cash provided by operating activities in 2008 increased $77 million compared to 2007 primarily due to decreased tax payments/increased tax refunds ($289 million), increased net accounts receivable/payable ($190 million), increased fuel cost recovery ($138 million) and increased pre-tax income ($131 million). These increases were partially offset by increased net regulatory assets and liabilities ($447 million) and increased net margin deposits ($247 million).

Net cash provided by operating activities in 2007 decreased $217 million compared to 2006 primarily due to the timing of fuel recovery ($204 million), increased tax payments ($10 million), increased interest payments ($40 million), increased gas storage inventory ($36 million) and decreased net accounts receivable/payable ($178 million). These decreases were partially offset by decreased reductions in customer margin deposit requirements ($76 million) and decreases in our margin deposit requirements ($145 million).

Cash Used in Investing Activities

Net cash used in investing activities increased $68 million in 2008 compared to 2007 due to increased investment in unconsolidated affiliates of $167 million, primarily related to the SESH pipeline project, which was partially offset by decreased capital expenditures of $94 million.

Net cash used in investing activities increased $244 million in 2007 compared to 2006 due to increased capital expenditures of $107 million primarily related to pipeline projects for our Interstate Pipelines business segment, increased notes receivable from unconsolidated affiliates of $148 million and increased investment in unconsolidated affiliates of $26 million, primarily related to the SESH pipeline project.

Cash Provided by Financing Activities

Net cash provided by financing activities in 2008 increased $27 million compared to 2007 primarily due to increased borrowings under revolving credit facilities ($779 million) and increased proceeds from long-term debt ($188 million), which were partially offset by increased repayments of long-term debt ($825 million) and decreased short-term borrowings ($124 million).

Net cash provided by financing activities in 2007 increased $410 million compared to 2006 primarily due to increased borrowings under revolving credit facilities ($334 million) and increased proceeds from long-term debt ($576 million), which were partially offset by increased repayments of long-term debt ($319 million), increased dividend payments ($31 million) and decreased short-term borrowings ($142 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 2009 include the following:

- approximately $1.1 billion of capital expenditures;
- maturing long-term debt aggregating approximately $216 million, including $208 million of transition bonds; and
- dividend payments on CenterPoint Energy common stock and interest payments on debt.

We expect that borrowings under our credit facilities and anticipated cash flows from operations will be sufficient to meet our anticipated cash needs in 2009. 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 and additional credit facilities may not, however, be available to us on acceptable terms.

The following table sets forth our capital expenditures for 2008 and estimates of our capital requirements for 2009 through 2013 (in millions):

	2008	2009	2010	2011	2012	2013
Electric Transmission & Distribution	$ 481	$ 422	$ 591	$ 579	$ 504	$ 506
Natural Gas Distribution	214	155	234	241	243	249
Competitive Natural Gas Sales and Services	8	3	3	3	3	3
Interstate Pipelines	189	202	151	87	67	70
Field Services	122	277	142	82	93	85
Other Operations	39	39	38	39	31	27
Total	$ 1,053	$ 1,098	$1,159	$1,031	$ 941	$ 940

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

Contractual Obligations	Total	2009	2010-2011	2012-2013	2014 and thereafter
Transition bond debt	$ 2,589	$ 208	$ 461	$ 546	$ 1,374
Other long-term debt(1)	8,624	8	792	2,732	5,092
Interest payments — transition bond debt(2)	794	140	227	177	250
Interest payments — other long-term debt(2)	4,812	481	948	794	2,589
Short-term borrowings	153	153	—	—	—
Capital leases	1	—	—	—	1
Operating leases(3)	75	14	23	13	25
Benefit obligations(4)	—	—	—	—	—
Purchase obligations(5)	24	24	—	—	—
Non-trading derivative liabilities	134	87	41	6	—
Other commodity commitments(6)	3,520	776	911	877	956
Income taxes(7)	121	121	—	—	—
Other	30	5	13	12	—
Total contractual cash obligations	$20,877	$2,017	$ 3,416	$ 5,157	$10,287

(1) ZENS obligations are included in 2029 at their contingent principal amount of $817 million. These obligations are exchangeable for cash at any time at the option of the holders for 95% of the current value of the Time Warner reference shares ($218 million at December 31, 2008), as discussed in Note 6 to our consolidated financial statements.

(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, 2008. 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 10(b) to our consolidated financial statements.

(4) Material contributions to our qualified pension plan are not expected in 2009. However, we expect to contribute approximately $9 million and $18 million, respectively, to our non-qualified pension and postretirement benefits plans in 2009.

(5) Represents capital commitments for material in connection with the construction of a pipeline by our Interstate Pipelines business segment. This project has been included in the table of capital expenditures presented above.

(6) For a discussion of other commodity commitments, please read Note 10(a) to our consolidated financial statements.

(7) Represents estimated income tax liability for settled positions for tax years under examination. In addition, as of December 31, 2008, the liability for uncertain income tax positions was $117 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 these liabilities might be paid.

Off-Balance Sheet Arrangements. Other than operating leases and the guaranties described below, 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. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for CERC's benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, we, CERC and RRI amended that agreement and CERC released the letters of credit it held as security. Under the revised agreement RRI agreed to provide cash or new letters of credit to secure CERC against exposure under the remaining guaranties as calculated under the new agreement if and to the extent changes in market conditions exposed CERC to a risk of loss on those guaranties.

The potential exposure to CERC under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under these transportation contracts, which will be effective until 2018, was approximately $108 million as of December 31, 2008. RRI continues to meet its obligations under the contracts, and on the basis of market conditions, we and CERC have not required additional security. However, if RRI should fail to perform its obligations under the contracts or if RRI should fail to provide adequate security in the event market conditions change adversely, we would retain our exposure to the counterparty under the guaranty.

Debt Financing Transactions. Pursuant to a financing order issued by the Texas Utility Commission in September 2007, in February 2008 a subsidiary of CenterPoint Houston issued approximately $488 million in transition bonds in two tranches with interest rates of 4.192% and 5.234% and final maturity dates in February 2020 and February 2023, respectively. Scheduled final payment dates are February 2017 and February 2020. Through issuance of the transition bonds, CenterPoint Houston securitized transition property of approximately $483 million representing the remaining balance of the CTC, adjusted to refund certain unspent environmental retrofit costs and to recover the amount of the fuel reconciliation settlement.

In April 2008, we purchased $175 million principal amount of pollution control bonds issued on our behalf at 102% of their principal amount. Prior to the purchase, $100 million principal amount of such bonds had a fixed rate of interest of 7.75% and $75 million principal amount of such bonds had a fixed rate of interest of 8%. Depending on market conditions, we may remarket both series of bonds, at 100% of their principal amounts, in 2009.

In April 2008, we called our 3.75% convertible senior notes for redemption on May 30, 2008. At the time of the announcement, the notes were convertible at the option of the holders, and substantially all of the notes were submitted for conversion on or prior to the May 30, 2008 redemption date. During the year ended December 31, 2008, we issued 16.9 million shares of our common stock and paid cash of approximately $532 million to settle conversions of approximately $535 million principal amount of our 3.75% convertible senior notes.

In May 2008, we issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.50%. The proceeds from the sale of the senior notes were used for general corporate purposes, including the satisfaction of cash payment obligations in connection with conversions of our 3.75% convertible senior notes as discussed above.

In May 2008, CERC Corp. issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.00%. The proceeds from the sale of the senior notes were used for general corporate purposes, including capital expenditures, working capital and loans to or investments in affiliates.

In December 2008, CERC entered into an asset management agreement whereby it sold $110 million of its natural gas in storage and agreed to repurchase an equivalent amount of natural gas during the 2008-2009 winter heating season for payments totaling $114 million. This transaction was accounted for as a financing and, as of December 31, 2008, the consolidated financial statements reflect natural gas inventory of $75 million and a financing obligation of $75 million related to this transaction.

In January 2009, CenterPoint Houston issued $500 million principal amount of general mortgage bonds, due in March 2014 with an interest rate of 7.00%. The proceeds from the sale of the bonds were used for general corporate purposes, including the repayment of outstanding borrowings under its revolving credit facility and from the money pool, capital expenditures and storm restoration costs associated with Hurricane Ike.

Equity Financing Transactions. In 2008, we received proceeds of approximately $65 million from the sale of approximately 4.9 million common shares to our defined contribution plan and proceeds of approximately $13 million from the sale of approximately 0.9 million common shares to participants in our enhanced dividend reinvestment plan.

Credit and Receivables Facilities. In November 2008, CenterPoint Houston entered into a $600 million 364-day credit facility. The credit facility will terminate if bonds are issued to securitize the costs incurred as a result of Hurricane Ike and if those bonds are issued prior to the November 24, 2009 expiration of the facility. CenterPoint Houston expects to seek legislative and regulatory approval for the issuance of such bonds during 2009.

The 364-day credit facility is secured by a pledge of $600 million of general mortgage bonds issued by CenterPoint Houston. Borrowing costs for London Interbank Offered Rate (LIBOR)-based loans will be at a margin of 2.25 percent above LIBOR rates, based on CenterPoint Houston’s current ratings. In addition, CenterPoint Houston will pay lenders, based on current ratings, a per annum commitment fee of 0.5 percent for their commitments under the facility and a quarterly duration fee of 0.75 percent on the average amount of outstanding borrowings during the quarter. The spread to LIBOR and the commitment fee fluctuate based on the borrower’s credit rating. The facility contains covenants, including a debt (excluding transition and other securitization bonds) to total capitalization covenant.

Our $1.2 billion credit facility has a first drawn cost of LIBOR plus 55 basis points based on our current credit ratings. The facility contains a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant, which was modified (i) in August 2008 so that the permitted ratio of debt to EBITDA would continue at its then-current level for the remaining term of the facility and (ii) in November 2008 so that the permitted ratio of debt to EBITDA would be temporarily increased until the earlier of December 31, 2009 or CenterPoint Houston’s issuance of bonds to securitize the costs incurred as a result of Hurricane Ike, after which time the permitted ratio would revert to the level that existed prior to the November 2008 modification.

CenterPoint Houston’s $289 million credit facility’s first drawn cost is LIBOR plus 45 basis points based on CenterPoint Houston’s current credit ratings. The facility contains a debt (excluding transition and other securitization bonds) to total capitalization covenant.

CERC Corp.’s $950 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.

Under our $1.2 billion credit facility, CenterPoint Houston's $289 million credit facility and CERC Corp's $950 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.

In November 2008, CERC replaced a receivables facility that had expired in October 2008 with a new receivables facility that expires in November 2009. Availability under the new facility ranges from $128 million to $375 million, reflecting seasonal changes in receivables balances.

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.

As of February 13, 2009, we had the following facilities (in millions):

Date Executed	Company	Type of Facility	Size of Facility	Amount Utilized at February 13, 2009	Termination Date
June 29, 2007	CenterPoint Energy	Revolver	$1,156	$ 184 (2)	June 29, 2012
June 29, 2007	CenterPoint Houston	Revolver	289	4	June 29, 2012
June 29, 2007	CERC Corp.	Revolver	950 (1)	781 (1)	June 29, 2012
November 25, 2008	CERC Corp.	Receivables	375	—	November 24, 2009
November 25, 2008	CenterPoint Houston	Revolver	600	—	November 24, 2009

(1) Lehman Brothers Bank, FSB, stopped funding its commitments following the bankruptcy filing of its parent in September 2008, effectively causing a reduction to the total available capacity of $20 million under CERC Corp.'s facility.

(2) Includes $155 million of borrowings and $29 million of outstanding letters of credit.

(3) Includes $4 million of outstanding letters of credit.

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 $950 million CERC Corp. credit facility backstops a $915 million commercial paper program under which CERC Corp. began issuing commercial paper in February 2008. The CenterPoint Energy commercial paper is rated "Not Prime" by Moody's Investors Service, Inc. (Moody's), "A-2" by Standard & Poor's Rating Services (S&P), a division of The McGraw-Hill Companies, and "F3" by Fitch, Inc. (Fitch). The CERC Corp. commercial paper is rated "P-3" by Moody's, "A-2" by S&P, and "F2" by Fitch. 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. We cannot assure you that these ratings, or the credit ratings set forth below in "— Impact on Liquidity of a Downgrade in Credit Ratings," 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 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.

Securities Registered with the SEC. In October 2008, CenterPoint Energy and CenterPoint Houston jointly registered indeterminate principal amounts of CenterPoint Houston's general mortgage bonds 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. In addition, CERC Corp. has a shelf registration statement covering $500 million principal amount of senior debt securities.

Temporary Investments. As of February 13, 2009, 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. As of February 13, 2009, Moody's, S&P, and 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	Stable	BBB-	Stable	BBB-	Stable
CenterPoint Houston Senior Secured Debt (First Mortgage Bonds)	Baa2	Stable	BBB+	Stable	A-	Stable
CenterPoint Houston Senior Secured Debt (General Mortgage Bonds)	Baa2	Stable	BBB+	Stable	BBB+	Stable
CERC Corp. Senior Unsecured Debt	Baa3	Stable	BBB	Stable	BBB	Stable

(1) A "stable" outlook from Moody's indicates that Moody's does not expect to put the rating on review for an upgrade or downgrade within 18 months from when the outlook was assigned or last affirmed.

(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.

A decline in these credit ratings could increase borrowing costs under our $1.2 billion credit facility, CenterPoint Houston's $289 million credit facility and CERC Corp.'s $950 million credit facility. 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. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments.

In September 1999, we issued ZENS having an original principal amount of $1.0 billion of which $840 million remain outstanding. Each ZENS note is 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 each ZENS note. 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 that we own or from other sources. We own shares of TW 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 liabilities related to the ZENS notes and TW Common shares become current tax obligations when ZENS notes are exchanged or otherwise retired and TW Common shares are sold. A tax obligation of approximately $378 million would have been payable with respect to the ZENS for the 2008 tax year if all of the ZENS had been exchanged for cash on December 31, 2008. The ultimate tax obligation 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. The American Recovery and Reinvestment Act of 2009, enacted on February 17, 2009, allows us to elect to defer this tax obligation until 2014 and recognize it over the period from 2014 through 2018 for any ZENS retired in 2009 or 2010.

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, 2008, the amount posted as collateral aggregated approximately $229 million. 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 on two business days' notice up to the amount of its previously unsecured credit limit. We estimate that as of December 31, 2008, unsecured credit limits extended to CES by counterparties aggregate $250 million; however, utilized credit capacity is significantly lower. In addition, CERC Corp. and its subsidiaries purchase natural gas under supply agreements that contain an aggregate credit threshold of $100 million based on CERC Corp.'s S&P Senior Unsecured Long-Term Debt rating of BBB. Upgrades and downgrades from this BBB rating will increase and decrease the aggregate credit threshold accordingly.

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 $160 million, the amount depending on seasonal variations in transportation levels.

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, four outstanding series of our senior notes, aggregating $950 million in principal amount as of February 13, 2009, 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 gas purchases, gas price hedging and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, particularly given gas price levels and volatility;

- 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 regulatory actions;
- the ability of RRI and its subsidiaries to satisfy their obligations as the principal customers of CenterPoint Houston and in respect of RRI'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;
- 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 benefit plans;
- restoration costs and revenue losses resulting from 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 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 bonds, to EBITDA covenant. Such covenant was modified twice in 2008 to provide additional debt capacity. The second modification was to provide debt capacity for the financing of system restoration costs following Hurricane Ike. 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

Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), 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 SFAS No. 71. 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, as defined in SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5), 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, 2008, we had recorded regulatory assets of $3.7 billion and regulatory liabilities of $821 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 SFAS No. 142, "Goodwill and Other Intangible Assets." No impairment of goodwill was indicated based on our annual analysis as of July 1, 2008. 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.

Asset Retirement Obligations

We account for our long-lived assets under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), and Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations — An Interpretation of SFAS No. 143" (FIN 47). SFAS No. 143 and FIN 47 require that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and FIN 47, and costs recovered through the ratemaking process.

We estimate the fair value of asset retirement obligations by calculating the discounted cash flows that are dependent upon the following components:

- Inflation adjustment — The estimated cash flows are adjusted for inflation estimates for labor, equipment, materials, and other disposal costs;

- Discount rate — The estimated cash flows include contingency factors that were used as a proxy for the market risk premium; and

- Third-party markup adjustments — Internal labor costs included in the cash flow calculation were adjusted for costs that a third party would incur in performing the tasks necessary to retire the asset.

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 3.0%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by approximately the same percentage. At December 31, 2008, our estimated cost of retiring these assets is approximately $63 million.

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 2(p) 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 plans in 2007 and 2008. The minimum funding requirements for these plans did not require contributions for the respective years.

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 $9 million and $8 million in 2007 and 2008, respectively.

In accordance with SFAS No. 87, "Employers' Accounting for Pensions," 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.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158). SFAS No. 158 requires us, as the sponsor of a plan, 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 a result of the adoption of SFAS No. 158 as of December 31, 2006, we recorded a regulatory asset of $466 million and a charge to accumulated comprehensive income of $79 million, net of tax.

At December 31, 2008, the projected benefit obligation exceeded the market value of plan assets of our pension plans by $434 million. Changes in interest rates or the market values of the securities held by the plan during 2009 could materially, positively or negatively, change our funded status and affect the level of pension expense and required contributions.

Pension expense was $46 million, $15 million and $1 million for 2006, 2007 and 2008, 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, 2008, our qualified pension plan had an expected long-term rate of return on plan assets of 8.00%, which was 0.50% lower than the rate assumed as of December 31, 2007. 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, 2008, the projected benefit obligation was calculated assuming a discount rate of 6.90%, which is a 0.50% increase from the 6.40% discount rate assumed in 2007. 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 expense for 2009, including the benefit restoration plan, is estimated to be $112 million, of which we expect $89 million to impact pre-tax earnings, based on an expected return on plan assets of 8.0% and a discount rate of 6.90% as of December 31, 2008. If the expected return assumption were lowered by 0.5% (from 8.00% to 7.50%), 2009 pension expense would increase by approximately $6 million.

As of December 31, 2008, the pension plan projected benefit obligation exceeded plan assets (including the unfunded benefit restoration plan) by $434 million. If the discount rate were lowered by 0.5% (from 6.90% to 6.40%), the assumption change would increase our projected benefit obligation and 2009 pension expense by approximately $74 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, 2008 by $59 million and would result in a charge to comprehensive income in 2008 of $10 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, 2008, we had outstanding long-term debt, bank loans, lease obligations, and our obligations under our ZENS that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $563 million and $1.5 billion at December 31, 2007 and 2008, respectively. If the floating interest rates were to increase by 10% from December 31, 2008 rates, our combined interest expense would increase by approximately $3 million annually.

At December 31, 2007 and 2008, we had outstanding fixed-rate debt (excluding indexed debt securities) aggregating $9.2 billion and $9.0 billion, respectively, in principal amount and having a fair value of $9.7 billion and $8.5 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 8 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $310 million if interest rates were to decline by 10% from their levels at December 31, 2008. 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 6 to our consolidated financial statements, the ZENS obligation is bifurcated into a debt component and a derivative component. The debt component of $117 million at December 31, 2008 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 $19 million if interest rates were to decline by 10% from levels at December 31, 2008. Changes in the fair value of the derivative component, a $133 million recorded liability at December 31, 2008, 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, 2008 levels, the fair value of the derivative component liability would increase by approximately $2 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 21.6 million shares of TW Common, which we hold to facilitate our ability to meet our obligations under the ZENS. Please read Note 6 to our consolidated financial statements for a discussion of our ZENS obligation. A decrease of 10% from the December 31, 2008 market value of TW Common would result in a net loss of approximately $5 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, 2008, the recorded fair value of our non-trading energy derivatives was a net liability of $183 million (before collateral). The net liability consisted of a net liability of $224 million associated with price stabilization activities of our Natural Gas Distribution business segment and a net asset of $41 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, 2008 levels would have increased the fair value of our non-trading energy derivatives net liability by $118 million with all of the increase attributable to price stabilization activities related to our Natural Gas Distribution business segment. There would be no consolidated income statement impact of the $118 million as the Natural Gas Distribution segment records the offset to net over/under recovered gas cost liabilities or assets on the balance sheet.

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, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 February 25, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2009

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, 2008, 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, 2008, 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, 2008 of the Company and our report dated February 25, 2009 expressed an unqualified opinion on those financial statements.

DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2009

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, 2008.

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, 2008 which is included herein on page 60.

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

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

February 25, 2009

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2006	2007	2008
	(In millions, except for share amounts)		
Revenues	$ 9,319	$ 9,623	$ 11,322
Expenses:			
Natural gas	5,909	5,995	7,466
Operation and maintenance	1,399	1,440	1,502
Depreciation and amortization	599	631	708
Taxes other than income taxes	367	372	373
Total	8,274	8,438	10,049
Operating Income	1,045	1,185	1,273
Other Income (Expense):			
Gain (loss) on Time Warner investment	94	(114)	(139)
Gain (loss) on indexed debt securities	(80)	111	128
Interest and other finance charges	(470)	(503)	(466)
Interest on transition bonds	(130)	(123)	(136)
Distribution from AOL Time Warner litigation settlement	—	32	—
Additional distribution to ZENS holders	—	(27)	—
Equity in earnings of unconsolidated affiliates	6	16	51
Other, net	29	17	14
Total	(551)	(591)	(548)
Income Before Income Taxes	494	594	725
Income tax expense	(62)	(195)	(278)
Net Income	$ 432	$ 399	$ 447
Basic Earnings Per Share	$ 1.39	$ 1.25	$ 1.33
Diluted Earnings Per Share	$ 1.33	$ 1.17	$ 1.30

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2006	2007	2008
		(In millions)	
Net income	$ 432	$ 399	$ 447
Other comprehensive income (loss):			
Adjustment to pension and other postretirement plans (net of tax of $-0-, $28 and $32)	—	34	(79)
Minimum pension liability adjustment (net of tax of $6, $-0- and $-0-)	12	—	—
Net deferred gain (loss) from cash flow hedges (net of tax of $11, $6 and $2)	22	11	(4)
Reclassification of deferred loss (gain) from cash flow hedges realized in net income (net of tax of $8, $14 and $2)	14	(20)	(4)
Other comprehensive income (loss)	48	25	(87)
Comprehensive income	$ 480	$ 424	$ 360

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2008
	(In millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 129	$ 167
Investment in Time Warner common stock	357	218
Accounts receivable, net	910	1,009
Accrued unbilled revenues	558	541
Inventory	490	569
Non-trading derivative assets	38	118
Prepaid expense and other current assets	306	413
Total current assets	2,788	3,035
Property, Plant and Equipment, net	9,740	10,296
Other Assets:		
Goodwill	1,696	1,696
Regulatory assets	2,993	3,684
Non-trading derivative assets	11	20
Investment in unconsolidated affiliates	88	345
Notes receivable from unconsolidated affiliates	148	323
Other	408	277
Total other assets	5,344	6,345
Total Assets	$ 17,872	$ 19,676
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Short-term borrowings	$ 232	$ 153
Current portion of long-term debt	1,315	333
Indexed debt securities derivative	261	133
Accounts payable	726	897
Taxes accrued	316	189
Interest accrued	170	180
Non-trading derivative liabilities	61	87
Accumulated deferred income taxes, net	350	372
Other	360	504
Total current liabilities	3,791	2,848
Other Liabilities:		
Accumulated deferred income taxes, net	2,235	2,609
Unamortized investment tax credits	31	24
Non-trading derivative liabilities	14	47
Benefit obligations	499	833
Regulatory liabilities	828	821
Other	300	276
Total other liabilities	3,907	4,610
Long-term Debt	8,364	10,181
Commitments and Contingencies (Note 10)		
Shareholders' Equity	1,810	2,037
Total Liabilities and Shareholders' Equity	$ 17,872	$ 19,676

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31, 2006	2007	2008
		(In millions)	
Cash Flows from Operating Activities:			
Net income	$ 432	$ 399	$ 447
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	599	631	708
Amortization of deferred financing costs	56	65	28
Deferred income taxes	(241)	—	487
Tax and interest reserves reductions related to ZENS and ACES settlement	(107)	—	—
Unrealized loss (gain) on Time Warner investment	(94)	114	139
Unrealized loss (gain) on indexed debt securities	80	(111)	(128)
Write-down of natural gas inventory	66	11	30
Equity in earnings of unconsolidated affiliates, net of distributions	(5)	(13)	(51)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	262	—	(82)
Inventory	(82)	(102)	(109)
Taxes receivable	53	—	—
Accounts payable	(269)	(185)	87
Fuel cost over (under) recovery	111	(93)	45
Non-trading derivatives, net	(18)	11	(25)
Margin deposits, net	(156)	65	(182)
Interest and taxes accrued	230	(33)	(118)
Net regulatory assets and liabilities	79	81	(366)
Other current assets	(76)	13	(27)
Other current liabilities	18	(20)	29
Other assets	48	(20)	(20)
Other liabilities	6	(51)	(8)
Other, net	(1)	12	(33)
Net cash provided by operating activities	991	774	851
Cash Flows from Investing Activities:			
Capital expenditures	(1,007)	(1,114)	(1,020)
Increase in restricted cash of transition bond companies	(32)	(1)	(11)
Increase in notes receivable from unconsolidated affiliates	—	(148)	(175)
Investment in unconsolidated affiliates	(13)	(39)	(206)
Other, net	(4)	2	44
Net cash used in investing activities	(1,056)	(1,300)	(1,368)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	187	45	(79)
Long-term revolving credit facility, net	(3)	331	1,110
Proceeds from long-term debt	324	900	1,088
Payments of long-term debt	(229)	(548)	(1,373)
Debt issuance costs	(5)	(9)	(26)
Payment of common stock dividends	(187)	(218)	(246)
Proceeds from issuance of common stock, net	27	22	80
Other, net	4	5	1
Net cash provided by financing activities	118	528	555
Net Increase in Cash and Cash Equivalents	53	2	38
Cash and Cash Equivalents at Beginning of Year	74	127	129
Cash and Cash Equivalents at End of Year	$ 127	$ 129	$ 167
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 532	$ 572	$ 586
Income taxes (refunds), net	195	205	(84)
Non-cash transactions:			
Accounts payable related to capital expenditures	173	75	96

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED SHAREHOLDERS' EQUITY

	2006		2007		2008	
	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	310	3	314	3	323	3
Issuances related to benefit and investment plans	4	—	2	—	6	—
Issuances related to convertible debt conversions	—	—	7	—	17	—
Balance, end of year	314	3	323	3	346	3
Additional Paid-in-Capital						
Balance, beginning of year	—	2,931	—	2,977	—	3,023
Issuances related to benefit and investment plans	—	46	—	46	—	112
Balance, end of year	—	2,977	—	3,023	—	3,135
Accumulated Deficit						
Balance, beginning of year		(1,600)		(1,355)		(1,172)
Net income		432		399		447
Cumulative effect of uncertain tax positions standard		—		2		—
Common stock dividends — $0.60 per share in 2006, $0.68 per share in 2007, and $0.73 per share in 2008		(187)		(218)		(245)
Balance, end of year		(1,355)		(1,172)		(970)
Accumulated Other Comprehensive Loss						
Balance, end of year:						
Adjustment to pension and postretirement plans		(82)		(48)		(127)
Net deferred gain (loss) from cash flow hedges		13		4		(4)
Total accumulated other comprehensive loss, end of year		(69)		(44)		(131)
Total Shareholders' Equity		$ 1,556		$ 1,810		$ 2,037

See Notes to the Company's Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background

CenterPoint Energy, Inc. (the Company) is a public utility holding company. The Company'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, 2008, the Company's indirect wholly owned subsidiaries included:

- 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 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 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 the Company's reportable business segments, see Note 14.

(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 the Company and its wholly owned and majority owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company uses the equity method of accounting for investments in entities in which the Company has an ownership interest between 20% and 50% and exercises significant influence. The Company's investments in unconsolidated affiliates include a 50% ownership interest in Southeast Supply Header, LLC (SESH) which owns and operates a 270-mile interstate natural gas pipeline and a 50% interest in Waskom Gas Processing Company, a Texas general partnership, which owns and operates a natural gas processing plant. Other investments, excluding marketable securities, are carried at cost.

(c) Revenues

The Company 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

The Company records property, plant and equipment at historical cost. The Company expenses repair and maintenance costs as incurred. Property, plant and equipment include the following:

	Weighted Average Useful Lives (Years)	December 31, 2007	December 31, 2008
		(In millions)	
Electric Transmission & Distribution	27	$ 6,993	$ 7,256
Natural Gas Distribution	32	3,065	3,266
Competitive Natural Gas Sales and Services	23	59	67
Interstate Pipelines	56	2,194	2,334
Field Services	51	493	601
Other property	26	446	482
Total		13,250	14,006
Accumulated depreciation and amortization:			
Electric Transmission & Distribution		2,602	2,652
Natural Gas Distribution		590	708
Competitive Natural Gas Sales and Services		9	11
Interstate Pipelines		160	182
Field Services		29	28
Other property		120	129
Total accumulated depreciation and amortization		3,510	3,710
Property, plant and equipment, net		$ 9,740	$ 10,296

Goodwill by reportable business segment as of December 31, 2007 and 2008 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

The Company performs its goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that the carrying value of these assets 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 future 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.

The Company performed the test at July 1, 2008, the Company's annual impairment testing date, and determined that no impairment charge for goodwill was required.

The Company 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, as compared to the carrying value of the assets.

At December 31, 2007 and 2008, the Company's asset retirement obligations were $81 million and $63 million, respectively. The decrease in asset retirement obligations in 2008 of $18 million is primarily attributable to the increase in the credit-adjusted risk-free rate used to value the asset retirement obligations as of the end of the period.

The decrease in asset retirement obligations results in an increase in removal cost regulatory liabilities as discussed in Note 2(e).

(e) Regulatory Assets and Liabilities

The Company applies the accounting policies established in Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), to the Electric Transmission & Distribution business segment and the Natural Gas Distribution business segment and to portions of the Interstate Pipelines business segment.

The following is a list of regulatory assets/liabilities reflected on the Company's Consolidated Balance Sheets as of December 31, 2007 and 2008:

	December 31, 2007	December 31, 2008
	(In millions)	
Electric generation-related regulatory assets (1)	$ 545	$ 3
Securitized regulatory asset (1)	2,131	2,430
Unrecognized equity return	(220)	(207)
Unamortized loss on reacquired debt	79	73
Hurricane Ike restoration cost (2)	—	435
Pension and postretirement-related regulatory asset (3)	360	848
Other long-term regulatory assets	98	102
Total regulatory assets (2)	2,993	3,684
Electric generation-related regulatory liabilities	44	—
Estimated removal costs	734	779
Other long-term regulatory liabilities	50	42
Total regulatory liabilities	828	821
Total regulatory assets and liabilities, net	$ 2,165	$ 2,863

(1) As discussed in Note 8(b), the Company securitized approximately $483 million of electric generation-related regulatory assets in February 2008.

(2) Pending review and approval by the Public Utility Commission of Texas (Texas Utility Commission), the Company is not recording a return on its Hurricane Ike restoration costs, see Note 3(a). Other regulatory assets that are not earning a return were not material at December 31, 2007 and 2008.

(3) Upon adoption of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158), the Company recorded a regulatory asset for its unrecognized costs associated with operations that have historically recovered and currently recover pension and postretirement expenses in rates.

The Company's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2007 and 2008, these removal costs of $734 million and $779 million, respectively, are classified as regulatory liabilities in the Company's Consolidated Balance Sheets. A portion of the amount of removal costs that relate to asset retirement obligations have been reclassified from a regulatory liability to an asset retirement liability in accordance with Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47).

(f) Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization expense includes amortization of regulatory assets and other intangibles. See Notes 2(e) and 3(a) for additional discussion of these items.

The following table presents depreciation and amortization expense for 2006, 2007 and 2008.

	2006	2007	2008
Depreciation expense	$ 440	$ 455	$ 478
Amortization expense	159	176	230
Total depreciation and amortization expense	$ 599	$ 631	$ 708

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

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for subsidiaries that apply SFAS No. 71. Interest and AFUDC for subsidiaries that apply SFAS No. 71 are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During 2006, 2007 and 2008, the Company capitalized interest and AFUDC of $10 million, $21 million and $12 million, respectively.

(h) Income Taxes

The Company files a consolidated federal income tax return and follows a policy of comprehensive interperiod tax allocation. The Company uses the asset and liability method of accounting for deferred income taxes in accordance with SFAS No. 109, "Accounting for 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.

Prior to 2007, the Company evaluated uncertain income tax positions and recorded a tax liability for those positions that management believed were probable of an unfavorable outcome and could be reasonably estimated. Effective January 1, 2007, the Company accounts for the tax effects of uncertain income tax positions in accordance with FIN 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109" (FIN 48). The Company recognizes interest and penalties as a component of income tax expense. For additional information regarding income taxes, see Note 9.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $38 million and $35 million at December 31, 2007 and 2008, respectively. The provision for doubtful accounts in the Company's Statements of Consolidated Income for 2006, 2007 and 2008 was $35 million, $45 million and $54 million, respectively.

On November 25, 2008, CERC replaced a receivables facility that had terminated on October 28, 2008 with a new 364-day receivables facility. Availability under the new facility ranges from $128 million to $375 million, reflecting seasonal changes in receivables balances. At December 31, 2007 and 2008, the facility size was $300 and $128 million, respectively. As of December 31, 2007 and 2008, advances under the receivables facilities were $232 million and $78 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. Natural gas inventories of the Company'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 the Company's Natural Gas Distribution business segment are primarily valued at weighted average cost. During 2007 and 2008, the Company recorded $11 million and $30 million, respectively, in write-downs of natural gas inventory to the lower of average cost or market.

	December 31, 2007	December 31, 2008
	(In millions)	
Materials and supplies	$ 95	$ 128
Natural gas	395	441
Total inventory	$ 490	$ 569

(k) Derivative Instruments

The Company 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. Such contracts are recognized in the Company's Consolidated Balance Sheets at their fair value unless the Company elects the normal purchase and sales exemption for qualified physical transactions. A derivative contract may be designated as a normal purchase or sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business. If derivative contracts are designated as a cash flow hedge according to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), the effective portions of the changes in their fair values are reflected initially as a separate component of shareholders' equity and subsequently recognized in income at the same time the hedged items impact earnings. The ineffective portions of changes in fair values of derivatives designated as hedges are immediately recognized in income. Changes in other derivatives not designated as normal or as a cash flow hedge are recognized in income as they occur. The Company does not enter into or hold derivative instruments for trading purposes.

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

The Company'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

In accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), the Company reports "available-for-sale" securities at estimated fair value within other long-term assets in the Company's Consolidated Balance Sheets and any unrealized gain or loss, net of tax, as a separate component of shareholders' equity and accumulated other comprehensive income. In accordance with SFAS No. 115, the Company reports "trading" securities at estimated fair value in the Company's Consolidated Balance Sheets, and any unrealized holding gains and losses are recorded as other income (expense) in the Company's Statements of Consolidated Income.

As of December 31, 2007 and 2008, the Company held an investment in Time Warner Inc. (TW) common stock (TW Common), which was classified as a "trading" security. For information regarding this investment, see Note 6.

(m) Environmental Costs

The Company expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Company expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Company 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, the Company 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 in October 2001, December 2005 and February 2008, the Company 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. Cash and cash equivalents does not include restricted cash of $49 million and $60 million at December 31, 2007 and 2008, respectively, which is included in other current assets in the Company's Consolidated Balance Sheets. For additional information regarding transition bonds, see Notes 3(b) and 8(b). Cash and cash equivalents includes $128 million and $166 million at December 31, 2007 and 2008, respectively, that is held by the Company's transition bond subsidiaries solely to support servicing the transition bonds.

(o) New Accounting Pronouncements

In April 2007, the FASB issued Staff Position No. FIN 39-1, "Amendment of FASB Interpretation No. 39" (FIN 39-1), which permits companies that enter into master netting arrangements to offset cash collateral receivables or payables with net derivative positions under certain circumstances. The Company adopted FIN 39-1 effective January 1, 2008 and began netting cash collateral receivables and payables and also its derivative assets and liabilities with the same counterparty subject to master netting agreements.

In February 2007, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115" (SFAS No. 159). SFAS No. 159 permits the Company to choose, at specified election dates, to measure eligible items at fair value (the "fair value option"). The Company would report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting period. This accounting standard is effective as of the beginning of the first fiscal year that begins after November 15, 2007 but is not required to be applied. The Company currently has no plans to apply SFAS No. 159.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), "Business Combinations" (SFAS No. 141R). SFAS No. 141R will significantly change the accounting for business combinations. Under SFAS No. 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition date fair value with limited exceptions. SFAS No. 141R also includes a substantial number of new disclosure requirements and applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. As the provisions of SFAS No. 141R are applied prospectively, the impact to the Company cannot be determined until applicable transactions occur.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51" (SFAS No. 160). SFAS No. 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This accounting standard is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company will adopt SFAS No. 160 as of January 1, 2009. The Company expects that the adoption of SFAS No. 160 will not have a material impact on its financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133" (SFAS No. 161). SFAS No. 161 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133) and requires enhanced disclosures of derivative instruments and hedging activities such as the fair value of derivative instruments and presentation of their gains or losses in tabular format, as well as disclosures regarding credit risks and strategies and objectives for using derivative instruments. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The Company expects that the adoption of SFAS No. 161 will not have a material impact on its financial position, results of operations or cash flows.

In May 2008, the FASB issued FASB Staff Position (FSP) No. APB 14-1 "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)," which will change the accounting treatment for convertible securities that the issuer may settle fully or partially in cash. The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, with retrospective application required. Under the final FSP, cash settled convertible securities will be separated into their debt and equity components. The value assigned to the debt component will be the estimated fair value, as of the issuance date, of a similar debt instrument without the conversion feature, and the difference between the proceeds for the convertible debt and the amount reflected as a debt liability will be recorded as additional paid-in capital. As a result, the debt will be recorded at a discount reflecting its below market coupon interest rate. The debt will subsequently be accreted to its par value over its expected life, with the rate of interest that reflects the market rate at issuance being reflected on the income statement. The Company currently has no convertible debt that is within the scope of this FSP, but did during prior periods presented. Accordingly, the implementation of the FSP will have a non-cash affect on net income for prior periods and the consolidated balance sheets when the Company had contingently convertible debt outstanding. The effect on net income for the years ended December 31, 2007 and 2008 will be a decrease in net income of $4 million and $1 million, respectively. Upon adoption of this FSP, the effect on the balance sheet as of December 31, 2008 will be a credit to Additional Paid-In-Capital of $23 million, with an offsetting debit to retained earnings of $23 million.

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

Stock-Based Incentive Compensation Plans

The Company has long-term incentive compensation plans (LICPs) that provide for the issuance of stock-based incentives, including performance-based shares, performance-based units, restricted shares and stock options to officers and key employees. A maximum of approximately 34 million shares of CenterPoint Energy common stock is authorized to be issued under these plans.

Equity awards are granted to employees without cost to the participants. The performance shares are distributed based upon the achievement of certain objectives over a three-year performance cycle. The stock awards granted in 2006, 2007 and 2008 are subject to the operational condition that total common dividends declared during the three-year vesting period must be at least $1.80, $2.04 and $2.19 per share, respectively. The stock awards vest at the end of a three-year period. Upon vesting, both the performance shares and the stock awards are issued to the participants along with the value of dividend equivalents earned over the performance cycle or vesting period. The Company issues new shares in order to satisfy share-based payments related to LICPs.

Option awards are generally granted with an exercise price equal to the average of the high and low sales price of the Company's stock at the date of grant. These option awards generally become exercisable in one-third increments on each of the first through third anniversaries of the grant date and have 10-year contractual terms. No options were granted during 2006, 2007 and 2008.

The Company recorded LICP compensation expense of $10 million in each of the years ended December 31, 2006, 2007 and 2008.

The total income tax benefit recognized related to such arrangements was $4 million in each of the years ended December 31, 2006, 2007 and 2008. No compensation cost related to such arrangements was capitalized as a part of inventory or fixed assets in 2006, 2007 or 2008.

Compensation costs for performance shares and stock awards granted under the LICPs are measured using fair value and expected achievement levels on the grant date. Forfeitures are estimated on the date of grant and are adjusted as required through the remaining vesting period.

The following tables summarize the Company's LICP activity for 2008:

Stock Options

	Outstanding Options Year Ended December 31, 2008			
	Shares (Thousands)	Weighted-Average Exercise Price	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2007	6,770	$ 17.78		
Forfeited or expired	(629)	22.11		
Exercised	(285)	10.46		
Outstanding at December 31, 2008	5,856	17.67	2.5	$ 12
Exercisable at December 31, 2008	5,856	17.67	2.5	12

Performance Shares

	Outstanding and Non-Vested Shares Year Ended December 31, 2008			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2007	2,132	$ 14.21		
Granted	896	15.40		
Forfeited or cancelled	(569)	13.02		
Vested and released to participants	(357)	12.30		
Outstanding at December 31, 2008	2,102	15.37	1.1	$ 17

The non-vested and outstanding shares displayed in the above tables assume that shares are issued at the maximum performance level (150%). The aggregate intrinsic value reflects the impacts of current expectations of achievement and stock price.

Stock Awards

	Outstanding and Non-Vested Stock Awards Year Ended December 31, 2008			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2007	720	$ 14.45		
Granted	401	15.09		
Forfeited	(64)	14.84		
Vested and released to participants	(268)	12.72		
Outstanding at December 31, 2008	789	15.33	1.2	$ 10

The weighted-average grant-date fair values of awards granted were as follows for 2006, 2007 and 2008:

	Year Ended December 31,		
	2006	2007	2008
Performance shares	$ 13.05	$ 18.20	$ 15.40
Stock awards	12.96	18.29	15.09

The total intrinsic value of awards received by participants was as follows for 2006, 2007 and 2008:

	Year Ended December 31,		
	2006	2007	2008
		(In millions)	
Options exercised	$ 10	$ 13	$ 2
Performance shares	10	—	6
Performance units	—	3	—
Stock awards	7	4	5

As of December 31, 2008 there was $22 million of total unrecognized compensation cost related to non-vested LICP arrangements. That cost is expected to be recognized over a weighted-average period of 1.7 years.

Cash received from LICPs was $17 million, $22 million and $3 million for 2006, 2007 and 2008, respectively.

The actual tax benefit realized for tax deductions related to LICPs totaled $11 million, $7 million and $5 million, for 2006, 2007 and 2008, respectively.

Pension and Postretirement Benefits

The Company maintains a non-contributory qualified defined benefit 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. Prior to 1999, the pension plan accrued benefits based on years of service, final average pay and covered compensation. Certain employees participating in the plan as of December 31, 1998 automatically receive the greater of the accrued benefit calculated under the prior plan formula through 2008 or the cash balance formula. Participants have historically been 100% vested in their benefit after completing five years of service. Effective January 1, 2008, the Company changed the vesting schedule to provide for 100% vesting after three years to comply with the Pension Protection Act of 2006. In addition to the non-contributory qualified defined benefit plan, the Company maintains unfunded non-qualified benefit restoration plans which allow participants to receive the benefits to which they would have been entitled under the Company'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.

The Company 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, resulting from the implementation of accrual accounting, is being amortized over approximately 20 years.

On January 5, 2006, the Company offered a Voluntary Early Retirement Program (VERP) to approximately 200 employees who were age 55 or older with at least five years of service as of February 28, 2006. The election period was from January 5, 2006 through February 28, 2006. For those electing to accept the VERP, three years of age and service were added to their qualified pension plan benefit and three years of service were added to their postretirement benefit. The one-time additional pension and postretirement expense of $9 million is reflected in the table below as a benefit enhancement.

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

	Year Ended December 31,					
	2006		2007		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)					
Service cost	$ 37	$ 2	$ 37	$ 2	$ 31	$ 1
Interest cost	101	26	100	26	101	27
Expected return on plan assets	(143)	(12)	(149)	(12)	(147)	(12)
Amortization of prior service cost (credit)	(7)	2	(7)	—	(8)	3
Amortization of net loss	50	—	34	3	23	—
Amortization of transition obligation	—	7	—	7	—	7
Benefit enhancement	8	1	—	—	1	—
Net periodic cost	$ 46	$ 26	$ 15	$ 26	$ 1	$ 26

The Company used the following assumptions to determine net periodic cost relating to pension and postretirement benefits:

	December 31,					
	2006		2007		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Discount rate	5.70%	5.70%	5.85%	5.85%	6.40%	6.40%
Expected return on plan assets	8.50	8.00	8.50	7.60	8.50	7.60
Rate of increase in compensation levels	4.60	—	4.60	—	4.60	—

In determining net periodic benefits cost, the Company 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 the Company's pension, including benefit restoration, and postretirement plans. The measurement dates for plan assets and obligations were December 31, 2007 and 2008.

	December 31,			
	2007		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions, except for actuarial assumptions)			
Change in Benefit Obligation				
Benefit obligation, beginning of year	$ 1,776	$ 469	$ 1,645	$ 437
Service cost	37	2	31	1
Interest cost	100	26	101	27
Participant contributions	—	5	—	5
Benefits paid	(145)	(35)	(123)	(38)
Actuarial gain	(123)	(33)	(59)	(10)
Plan amendment	—	—	114	—
Medicare reimbursement	—	3	—	4
Benefit enhancement	—	—	1	—
Benefit obligation, end of year	1,645	437	1,710	426
Change in Plan Assets				
Plan assets, beginning of year	1,806	158	1,792	161
Employer contributions	9	22	8	27
Participant contributions	—	5	—	5
Benefits paid	(145)	(35)	(123)	(38)
Actual investment return	122	11	(401)	(20)
Plan assets, end of year	1,792	161	1,276	135
Funded status, end of year	$ 147	$ (276)	$ (434)	$ (291)
Amounts Recognized in Balance Sheets				
Other assets-other	$ 231	$ —	$ —	$ —
Current liabilities-other	(8)	(8)	(9)	(10)
Other liabilities-benefit obligations	(76)	(268)	(425)	(281)
Net asset (liability), end of year	$ 147	$ (276)	$ (434)	$ (291)
Actuarial Assumptions				
Discount rate	6.40%	6.40%	6.90%	6.90%
Expected return on plan assets	8.50	7.60	8.00	7.05%
Rate of increase in compensation levels	4.60	—	4.60	—
Healthcare cost trend rate assumed for the next year	—	7.00	—	6.50
Prescription drug cost trend rate assumed for the next year	—	13.00	—	12.00
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	—	2012	—	2011
Year that the prescription drug rate reaches the ultimate trend rate	—	2015	—	2014

At December 31, 2008, the pension benefit obligation increased by $114 million due to a plan amendment effective January 1, 2009. The amendment increased certain cash balance accounts in conjunction with a transition to a uniform cash balance program effective 2009.

The accumulated benefit obligation for all defined benefit pension plans was $1,623 million and $1,708 million as of December 31, 2007 and 2008, respectively.

The expected rate of return assumption was developed by reviewing the targeted asset allocations and historical index performance of the applicable asset classes over a 15-year period, adjusted for investment fees and diversification effects.

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 obligations specific to the characteristics of the Company's plans.

For measurement purposes, healthcare costs are assumed to increase 6.50% during 2009, after which this rate decreases until reaching the ultimate trend rate of 5.5% in 2011. Prescription drug costs are assumed to increase 12% during 2009, after which this rate decreases until reaching the ultimate trend rate of 5.5% in 2014.

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

	December 31,			
	2007		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)			
Unrecognized actuarial loss (gain)	$ 99	$ (4)	$ 181	$ 5
Unrecognized prior service cost (credit)	(6)	14	17	11
Unrecognized transition obligation	—	4	—	3
Net amount recognized in other comprehensive income	$ 93	$ 14	$ 198	$ 19

The changes in plan assets and benefit obligations recognized in other comprehensive income during 2008 are as follows (in millions):

	Pension Benefits	Postretirement Benefits
Net loss	$ 89	$ 9
Amortization of net loss	(7)	—
Prior service credit	22	—
Amortization of prior service credit (cost)	1	(3)
Amortization of transition obligation	—	(1)
Total recognized in comprehensive income	$105	$ 5

The total expense recognized in net periodic costs and other comprehensive income was $106 million and $31 million for pension and postretirement benefits, respectively, for the year ended December 31, 2008.

The amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost during 2009 are as follows (in millions):

	Pension Benefits	Postretirement Benefits
Unrecognized actuarial loss	$ 15	$ —
Unrecognized prior service cost	1	2
Amounts in comprehensive income to be recognized in net periodic cost in 2009	$ 16	$ 2

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

	December 31,			
	2007		2008	
	Pension Qualified	Pension Non-qualified	Pension Qualified	Pension Non-qualified
	(In millions)			
Accumulated benefit obligation	$ 1,541	$ 82	$ 1,622	$ 86
Projected benefit obligation	1,561	84	1,624	86
Plan assets	1,792	—	1,276	—

Assumed healthcare cost trend rates have a significant effect on the reported amounts for the Company'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	$ 17	$ 14
Effect on total of service and interest cost	1	1

The following table displays the weighted-average asset allocations as of December 31, 2007 and 2008 for the Company's pension and postretirement benefit plans:

	December 31,			
	2007		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Domestic equity securities	49%	26%	27%	26%
Global equity securities	11	—	8	—
International equity securities	12	9	18	9
Debt securities	27	64	46	65
Real estate	1	—	1	—
Cash	—	1	—	—
Total	100%	100%	100%	100%

In managing the investments associated with the benefit plans, the Company'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, the Company has adopted and maintains the following weighted average allocation targets for its benefit plans:

	Pension Benefits	Postretirement Benefits
Domestic equity securities	25-35%	21-31%
Global equity securities	7-13%	—
International equity securities	17-23%	4-14%
Debt securities	34-44%	60-70%
Real estate	0-5%	—
Cash	0-2%	0-2%

The pension plan did not include any holdings of CenterPoint Energy common stock as of December 31, 2007 or 2008.

The Company contributed $8 million and $20 million to its non-qualified pension and postretirement benefits plans in 2008, respectively. The Company expects to contribute approximately $9 million and $18 million to its non-qualified pension and postretirement benefits plans in 2009, respectively.

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

		Postretirement Benefit Plan	
	Pension Benefits	Benefit Payments	Medicare Subsidy Receipts
2009	$ 137	$ 34	$ (3)
2010	141	36	(4)
2011	142	38	(4)
2012	147	39	(5)
2013	150	41	(6)
2014-2018	755	221	(36)

Savings Plan

The Company has a 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%, which increased from 16% in prior years, of compensation. Effective January 1, 2009, the Company matches 100% of the first 6% of each employee's compensation contributed. The Company previously matched 75% of the first 6% of each employee's compensation contributed with the potential for an additional discretionary match of up to 50% 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, 2008, 21,352,777 shares of CenterPoint Energy's common stock were held by the savings plan, which represented 24.5% 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.

The Company's savings plan benefit expenses were $34 million, $35 million and $39 million in 2006, 2007 and 2008, respectively.

Postemployment Benefits

Net postemployment benefit costs 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) were $6 million in 2006. The Company recorded postemployment benefit income of $2 million and $1 million in 2007 and 2008, respectively.

Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2007 and 2008 was $37 million and $32 million, respectively, relating to postemployment obligations.

Other Non-Qualified Plans

The Company 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 the Company. During 2006, 2007 and 2008, the Company recorded benefit expense relating to these plans of $6 million, $7 million and $4 million, respectively. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2007 and 2008 was $100 million and $83 million, respectively, relating to deferred compensation plans.

Change in Control Agreements and Other Employee Matters

The Company has agreements with certain of its officers that generally provide, to the extent applicable, in the case of a change in control of the Company 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 the Company's board of directors prior to the renewal.

As of December 31, 2008, approximately 30% of the Company's employees are subject to collective bargaining agreements. One of the collective bargaining agreements covering approximately 5% of the Company's employees, Gas Workers Union Local No. 340, is scheduled to expire in 2009. The Company has a good relationship with this bargaining unit and expects to negotiate a new agreement in 2009.

(3) Regulatory Matters

(a) 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.

The strong Category 2 storm initially left more than 90% of CenterPoint Houston's more than 2 million metered customers without power, the largest outage in CenterPoint Houston's 130-year history. Most of the widespread power outages were due to power lines damaged by downed trees and debris blown by Hurricane Ike's winds. In addition, on Galveston Island and along the coastal areas of the Gulf of Mexico and Galveston Bay, the storm surge and flooding from rains accompanying the storm caused significant damage or destruction of houses and businesses served by CenterPoint Houston.

CenterPoint Houston estimates that total costs to restore the electric delivery facilities damaged as a result of Hurricane Ike will be in the range of $600 million to $650 million. As is common with electric utilities serving coastal regions, the poles, towers, wires, street lights and pole mounted equipment that comprise CenterPoint Houston's transmission and distribution system are not covered by property insurance, but office buildings and warehouses and their contents and substations are covered by insurance that provides for a maximum deductible of $10 million. Current estimates are that total losses to property covered by this insurance were approximately $17 million.

CenterPoint Houston has deferred the uninsured storm restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. As a result, storm restoration costs did not affect the Company's or CenterPoint Houston's reported net income for 2008. As of December 31, 2008, CenterPoint Houston recorded an increase of $145 million in construction work in progress and $435 million in regulatory assets for restoration costs incurred through December 31, 2008. Approximately $73 million of these costs are based on estimates and are included in accounts payable as of December 31, 2008. Additional restoration costs will continue to be incurred in 2009.

Assuming necessary enabling legislation is enacted by the Texas Legislature in the session that began in January 2009, CenterPoint Houston expects to seek a financing order from the Texas Utility Commission to obtain recovery of its storm restoration costs through the issuance of non-recourse securitization bonds similar to the storm recovery bonds issued by another Texas utility following the hurricanes that affected that utility's service territories in 2005. Assuming those bonds are issued, CenterPoint Houston will recover the amount of storm restoration costs determined by the Texas Utility Commission to have been prudently incurred out of the bond proceeds, with the bonds being repaid over time through a charge imposed on customers. Alternatively, if securitization is not available, recovery of those costs would be sought through traditional regulatory mechanisms. Under its 2006 rate case settlement, CenterPoint Houston is entitled to seek an adjustment to rates in this situation, even though in most instances its rates are frozen until 2010.

The natural gas distribution business of CERC (Gas Operations) also suffered some damage to its system in Houston, Texas and in other portions of its service territory across Texas and Louisiana. As of December 31, 2008, Gas Operations has deferred approximately $4 million of costs related to Hurricane Ike for recovery as part of future natural gas distribution rate proceedings.

(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 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 Reliant Energy, Inc. (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.

Review by the Texas Supreme Court of the court of appeals decision is at the discretion of the court. In November 2008, the Texas Supreme Court requested the parties to the Petitions for Review to submit briefs on the merits of the issues raised. Briefing at the Texas Supreme Court should be completed in the second quarter of 2009. Although the Texas Supreme Court has not indicated whether it will grant review of the lower court's decision, its request for full briefing on the merits allowed the parties to more fully explain their positions. There is no prescribed time in which the Texas Supreme Court must determine whether to grant review or, if review is granted, for a decision by that court. Although the Company 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, the Company 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, the Company 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 the Company'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, the Company 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 and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $170 million to $385 million (pre-tax) plus interest subsequent to December 31, 2008.

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, for the present value of certain deferred tax benefits associated with its former electric generation assets. The Company 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, the Company 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 the Company 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 the Company's results of operations, financial condition and cash flows in addition to any potential loss resulting from final resolution of the True-Up Order. In its opinion, the court of appeals ordered that this issue be remanded to the Texas Utility Commission, as that commission requested. No party, in the petitions for review or briefs filed with the Texas Supreme Court, has challenged that order by the court of appeals, though the Texas Supreme Court, if it grants review, will have authority to consider all aspects of the rulings above, not just those challenged specifically by the appellants. The Company and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate or administrative process. Although the Texas Utility Commission 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 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 the 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 of the appellants have requested further review from the Texas Supreme Court. The ultimate outcome of this matter cannot be predicted at this time. However, the Company does not expect the disposition of this matter to have a material adverse effect on the Company's or CenterPoint Houston's financial condition, results of operations or cash flows.

During the years ended December 31, 2006, 2007 and 2008, CenterPoint Houston recognized approximately $55 million, $42 million and $5 million, respectively, in operating income from the CTC. Additionally, during the years ended December 31, 2006, 2007 and 2008, CenterPoint Houston recognized approximately $13 million, $14 million and $13 million, respectively, of the allowed equity return not previously recognized. As of December 31, 2008, the Company had not recognized an allowed equity return of $207 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates.

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.

(c) Rate Proceedings

Texas. In March 2008, 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. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Texas Coast service territory. Of the 47 cities, 23 either affirmatively approved or allowed the filed rates to go into effect by operation of law. Nine other cities were represented by the Texas Coast Utilities Coalition (TCUC) and 15 cities were represented by the Gulf Coast Coalition of Cities (GCCC). In July 2008, Gas Operations reached a settlement agreement with the GCCC. That settlement agreement, if implemented across the entire Texas Coast service territory, would allow Gas Operations a $3.4 million annual increase in revenues. The TCUC cities denied the rate change request and Gas Operations appealed the denial of rates to the Railroad Commission. The Railroad Commission issued an order in October 2008, which, if implemented across the entire Texas Coast service territory, would result in an annual revenue increase of $3.7 million. Both the Railroad Commission order and the settlement provide for an annual rate adjustment mechanism to reflect changes in operating expenses and revenues as well as changes in capital investment and associated changes in revenue-related taxes. In December 2008, the Railroad Commission issued an order on rehearing. Parties have filed second motions for rehearing on this order. However, in December 2008, Gas Operations implemented the approved rates for the nine TCUC cities and the environs, subject to refund. The impact of the Railroad Commission's order on rehearing on the settled rates is still under review, and how rates will be conformed among all cities in the Texas Coast service territory is unknown at this time. A final decision from the Railroad Commission regarding the second motions for rehearing is expected no later than March 2009.

In September 2008, CenterPoint Houston filed an application with the Texas Utility Commission requesting an interim update to its wholesale transmission rate. The filing resulted in a revenue requirement increase of $22.5 million over rates then in effect. Approximately 74% will be paid by distribution companies other than CenterPoint Houston. The remaining 26% represents CenterPoint Houston's share. That amount cannot be included in rates until 2010 under the terms of the rate freeze implemented in the settlement of CenterPoint Houston's 2006 rate proceeding. In November 2008, the Texas Utility Commission approved CenterPoint Houston's request. The interim rates became effective for service on and after November 5, 2008.

Minnesota. In November 2006, the Minnesota Public Utilities Commission (MPUC) denied a request filed by Gas Operations for a waiver of MPUC rules in order to allow Gas Operations to recover approximately $21 million in unrecovered purchased gas costs related to periods prior to July 1, 2004. Those unrecovered gas costs were identified as a result of revisions to previously approved calculations of unrecovered purchased gas costs. Following that denial, Gas Operations recorded a $21 million adjustment to reduce pre-tax earnings in the fourth quarter of 2006 and reduced the regulatory asset related to these costs by an equal amount. In March 2007, following the MPUC's denial of reconsideration of its ruling, Gas Operations petitioned the Minnesota Court of Appeals for review of the MPUC's decision, and in May 2008 that court ruled that the MPUC had been arbitrary and capricious in denying Gas Operations a waiver. The court ordered the case remanded to the MPUC for reconsideration under the same principles the MPUC had applied in previously granted waiver requests. The MPUC sought further review of the court of appeals decision from the Minnesota Supreme Court, and in July 2008, the Minnesota Supreme Court agreed to review the decision. In January 2009, the Minnesota Supreme Court heard oral arguments. While there is no deadline for a decision, a decision is expected by the end of the third quarter of 2009. While no prediction can be made as to the ultimate outcome, this matter will have no negative impact on the Company's financial condition, results of operations or cash flows.

In November 2008, Gas Operations filed a request with the MPUC to increase its rates for utility distribution service. If approved by the MPUC, the proposed new rates would result in an overall increase in annual revenue of $59.8 million. The proposed increase would allow Gas Operations to recover increased operating costs, including higher bad debt and collection expenses, the cost of improved customer service and inflationary increases in other expenses. It also would allow recovery of increased costs related to conservation improvement programs and provide a return for the additional capital invested to serve its customers. In addition, Gas Operations is seeking 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. The MPUC is allowed ten months to issue a final decision; however, an extension of time can occur in certain circumstances.

(4) Derivative Instruments

The Company is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. The Company 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

Cash Flow Hedges. The Company has entered into certain derivative instruments that qualify as cash flow hedges under SFAS No. 133. The objective of these derivative instruments is to hedge the price risk associated with natural gas purchases and sales to reduce cash flow variability related to meeting the Company's wholesale and retail customer obligations. During the year ended December 31, 2006, hedge ineffectiveness resulted in a gain of $2 million and during both the years ended December 31, 2007 and 2008, hedge ineffectiveness resulted in a loss of less than $1 million from derivatives that qualify for and are designated as cash flow hedges. No component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness. If it becomes probable that an anticipated transaction being hedged will not occur, the Company realizes in net income the deferred gains and losses previously recognized in accumulated other comprehensive loss. When an anticipated transaction being hedged affects earnings, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in the Statements of Consolidated Income under the "Expenses" caption "Natural gas." Cash flows resulting from these transactions in non-trading energy derivatives are included in the Statements of Consolidated Cash Flows in the same category as the item being hedged. As of December 31, 2008, the Company expects less than $1 million in accumulated other comprehensive income to be reclassified as a decrease in Natural gas expense during the next twelve months.

The length of time the Company is hedging its exposure to the variability in future cash flows using derivative instruments that have been designated and have qualified as cash flow hedging instruments is less than one year. The Company's policy is not to exceed ten years in hedging its exposure.

Other Derivative Instruments. The Company enters into certain derivative instruments to manage physical commodity price risks that do not qualify or are not designated as cash flow or fair value hedges under SFAS No. 133. The Company utilizes these financial instruments to manage physical commodity price risks and does not engage in proprietary or speculative commodity trading. During the year ended December 31, 2006, the Company decreased natural gas expense from unrealized net gains of $34 million. During the year ended December 31, 2007, the Company increased natural gas expense from unrealized net losses of $10 million. During the year ended December 31, 2008, the Company increased 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.

Weather Derivatives. The Company has weather normalization or other rate mechanisms that mitigate the impact of weather in Arkansas, Louisiana, Oklahoma and a portion of Texas. The remaining Gas Operations jurisdictions, Minnesota, Mississippi and most of Texas, do not have such mechanisms. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of these operations.

In 2007, the Company entered into heating-degree day swaps to mitigate the effect of fluctuations from normal weather on its financial position and cash flows for the 2007-2008 winter heating season. The swaps were based on ten-year normal weather and provided for a maximum payment by either party of $18 million. In July 2008, the Company entered into heating-degree day swaps to mitigate the effect of fluctuations from normal weather on its financial position and cash flows for the 2008-2009 winter heating season. The swaps are based on ten-year normal weather and provide for a maximum payment by either party of $11 million. During the years ended December 31, 2007 and 2008, the Company recognized losses of $-0- and $17 million, respectively, related to these swaps. Such amounts were substantially offset by increased margin due to colder than normal weather. These weather derivative losses are included in revenues in the Statements of Consolidated Income.

Interest Rate Swaps. During 2002, the Company settled forward-starting interest rate swaps having an aggregate notional amount of $1.5 billion at a cost of $156 million, which was recorded in other comprehensive loss and was amortized into interest expense over the five-year life of the designated fixed-rate debt. The settlement amount was fully amortized at December 31, 2007. Amortization of amounts deferred in accumulated other comprehensive loss for 2006 and 2007 was $31 million and $20 million, respectively.

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

(b) Credit Risks

In addition to the risk associated with price movements, credit risk is also inherent in the Company'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 the non-trading derivative assets of the Company as of December 31, 2007 and 2008 (in millions):

	December 31, 2007		December 31, 2008	
	Investment Grade(1)	Total	Investment Grade(1)	Total
Energy marketers	$ 16	$ 18	$ 8	$ 9
Financial institutions	25	25	4	4
Retail end users (2)	3	7	5	125
Total	$ 44	$ 50	$ 17	$ 138

(1) "Investment grade" is primarily determined using publicly available credit ratings along with the consideration of credit support (such as parent company guaranties) and collateral, which encompass cash and standby letters of credit. For unrated counterparties, the Company performs financial statement analysis, considering contractual rights and restrictions and collateral, to create a synthetic credit rating.

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

(5) Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which requires additional disclosures about the Company's financial assets and liabilities that are measured at fair value. FASB Staff Position No. FAS 157-2 delays the effective date for SFAS No. 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, to fiscal years, and interim periods within those fiscal years, beginning after November 15, 2008. The Company has elected to defer the adoption of SFAS No. 157 for its goodwill impairment test and the measurement of asset retirement obligations until January 1, 2009 as permitted. Beginning in January 2008, assets and liabilities recorded at fair value in the Consolidated Balance Sheet are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined in SFAS No. 157 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 financial derivatives, investments and equity securities listed in active markets.

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.

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. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment, and considers factors specific to the asset. Generally, assets and liabilities carried at fair value and included in this category are financial derivatives.

The following table presents information about the Company's assets and liabilities (including derivatives that are presented net) measured at fair value on a recurring basis as of December 31, 2008, and indicates the fair value hierarchy of the valuation techniques utilized by the Company 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, 2008
			(in millions)		
Assets					
Corporate equities	$ 218	$ —	$ —	$ —	$ 218
Investments, including money market funds	70	—	—	—	70
Derivative assets	8	155	49	(74)	138
Total assets	$ 296	$ 155	$ 49	$ (74)	$ 426
Liabilities					
Indexed debt securities derivative	$ —	$ 133	$ —	$ —	$ 133
Derivative liabilities	44	244	107	(261)	134
Total liabilities	$ 44	$ 377	$ 107	$ (261)	$ 267

(1) Amounts represent the impact of legally enforceable master netting agreements that allow the Company to settle positive and negative positions and also cash collateral held or placed with the same counterparties.

The following table presents additional information about assets or liabilities, including derivatives that are measured at fair value on a recurring basis for which the Company has utilized Level 3 inputs to determine fair value, for the year ended December 31, 2008:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Derivative assets and liabilities, net
	(in millions)
Beginning liability balance as of January 1, 2008	$ (3)
Total gains or (losses) (realized and unrealized):	
Included in deferred fuel cost recovery	(10)
Included in earnings	(11)
Purchases, sales, other settlements, net:	
Included in deferred fuel cost recovery	(41)
Included in earnings	6
Net transfers into Level 3	1
Ending liability balance as of December 31, 2008	$ (58)
The amount of total gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ 7

(6) Indexed Debt Securities (ZENS) and Time Warner Securities

(a) Original Investment in Time Warner Securities

In 1995, the Company sold a cable television subsidiary to TW and received TW convertible preferred stock (TW Preferred) as partial consideration. In July 1999, the Company converted its 11 million shares of TW Preferred into 45.8 million shares of TW Common. A subsidiary of the Company now holds 21.6 million shares of TW Common which are classified as trading securities under SFAS No. 115 and are expected to be held to facilitate the Company's ability to meet its obligation under the 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS). Unrealized gains and losses resulting from changes in the market value of the TW Common are recorded in the Company's Statements of Consolidated Income.

(b) ZENS

In September 1999, the Company issued its ZENS having an original principal amount of $1.0 billion. ZENS are exchangeable for cash equal to the market value of a specified number of shares of TW common. The Company pays interest on the ZENS at an annual rate of 2% plus the amount of any quarterly cash dividends paid in respect of the shares of TW Common attributable to the ZENS. The principal amount of ZENS is subject to being increased or decreased to the extent that the annual yield from interest and cash dividends on the reference shares of TW Common is less than or more than 2.309%. This is defined in the ZENS instrument as "contingent principal." At December 31, 2008, ZENS having an original principal amount of $840 million and a contingent principal amount of $817 million were outstanding and were exchangeable, at the option of the holders, for cash equal to 95% of the market value of 21.6 million shares of TW Common deemed to be attributable to the ZENS. At December 31, 2008, the market value of such shares was approximately $218 million, which would provide an exchange amount of $246 for each $1,000 original principal amount of ZENS. At maturity of the ZENS in 2029, the Company will be obligated to pay in cash the higher of the contingent principal amount of the ZENS or an amount based on the then-current market value of TW Common, or other securities distributed with respect to TW Common.

The ZENS obligation is bifurcated into a debt component and a derivative component (the holder's option to receive the appreciated value of TW Common at maturity). The bifurcated debt component accretes through interest charges at 17.4% annually up to the contingent principal amount of the ZENS in 2029. Such accretion will be reduced by annual cash interest payments, as described above. The derivative component is recorded at fair value and changes in the fair value of the derivative component are recorded in the Company's Statements of Consolidated

Income. During 2006, 2007 and 2008, the Company recorded a gain (loss) of $94 million, $(114) million and $(139) million, respectively, on the Company's investment in TW Common. During 2006, 2007 and 2008, the Company recorded a gain (loss) of $(80) million, $111 million and $128 million, respectively, associated with the fair value of the derivative component of the ZENS obligation. Changes in the fair value of the TW Common held by the Company are expected to substantially offset changes in the fair value of the derivative component of the ZENS.

The following table sets forth summarized financial information regarding the Company's investment in TW Common and the Company's ZENS obligation (in millions).

	TW Investment	Debt Component of ZENS	Derivative Component of ZENS
Balance at December 31, 2005	$ 377	$ 109	$ 292
Accretion of debt component of ZENS	—	19	—
2% interest paid	—	(17)	—
Loss on indexed debt securities	—	—	80
Gain on TW Common	94	—	—
Balance at December 31, 2006	471	111	372
Accretion of debt component of ZENS	—	20	—
2% interest paid	—	(17)	—
Gain on indexed debt securities	—	—	(111)
Loss on TW Common	(114)	—	—
Balance at December 31, 2007	357	114	261
Accretion of debt component of ZENS	—	20	—
2% interest paid	—	(17)	—
Gain on indexed debt securities	—	—	(128)
Loss on TW Common	(139)	—	—
Balance at December 31, 2008	$ 218	$ 117	$ 133

(7) Equity

(a) Capital Stock

CenterPoint Energy has 1,020,000,000 authorized shares of capital stock, comprised of 1,000,000,000 shares of $0.01 par value common stock and 20,000,000 shares of $0.01 par value preferred stock.

(b) Shareholder Rights Plan

The Company has a Shareholder Rights Plan that states that each share of its common stock includes one associated preference stock purchase right (Right) which entitles the registered holder to purchase from the Company a unit consisting of one-thousandth of a share of Series A Preference Stock. The Rights, which expire on December 11, 2011, are exercisable upon some events involving the acquisition of 20% or more of the Company's outstanding common stock. Upon the occurrence of such an event, each Right entitles the holder to receive common stock with a current market price equal to two times the exercise price of the Right. At any time prior to becoming exercisable, the Company may repurchase the Rights at a price of $0.005 per Right. There are 700,000 shares of Series A Preference Stock reserved for issuance upon exercise of the Rights.

(8) Short-term Borrowings and Long-term Debt

	December 31, 2007		December 31, 2008	
	Long-Term	Current(1)	Long-Term	Current(1)
	(In millions)			
Short-term borrowings:				
CERC Corp. receivables facility	$ —	$ 232	$ —	$ 78
Inventory financing	—	—	—	75
Total short-term borrowings	—	232	—	153
Long-term debt:				
CenterPoint Energy:				
ZENS(2)	—	114	—	117
Senior notes 5.875% to 7.25% due 2008 to 2018	650	200	950	—
Convertible senior notes 3.75% due 2023(3)	—	535	—	—
Pollution control bonds 4.00% due 2015(4)	151	—	151	—
Pollution control bonds 4.70% to 8.00% due 2011 to 2030(5)	1,046	—	871	—
Bank loans due 2012(6)	131	—	264	—
Other	—	—	12	1
CenterPoint Houston:				
First mortgage bonds 9.15% due 2021	102	—	102	—
General mortgage bonds 5.60% to 6.95% due 2013 to 2033	1,262	—	1,262	—
Pollution control bonds 3.625% to 5.60% due 2012 to 2027(7)	229	—	229	—
Transition Bonds 4.192% to 5.63% due 2008 to 2020	2,101	159	2,381	208
Bank loans due 2012(6)	50	—	251	—
CERC Corp.:				
Convertible subordinated debentures 6.00% due 2012	50	7	44	7
Senior notes 5.95% to 7.875% due 2008 to 2037	2,447	300	2,747	—
Bank loans due 2012(6)	150	—	926	—
Other	1	—	1	—
Unamortized discount and premium(8)	(6)	—	(10)	—
Total long-term debt	8,364	1,315	10,181	333
Total debt	$ 8,364	$ 1,547	$ 10,181	$ 486

(1) Includes amounts due or exchangeable within one year of the date noted.

(2) The Company's ZENS obligation is bifurcated into a debt component and an embedded derivative component. For additional information regarding ZENS, see Note 6(b). As ZENS are exchangeable for cash at any time at the option of the holders, these notes are classified as a current portion of long-term debt.

(3) Substantially all of the Company's 3.75% convertible senior notes were submitted for conversion in 2008, as described in Note 8(b), "Long-term Debt — Convertible Debt."

(4) These series of debt are secured by first mortgage bonds of CenterPoint Houston.

(5) $527 million of these series of debt is secured by general mortgage bonds of CenterPoint Houston.

(6) Classified as long-term debt because the termination dates of the facilities under which the funds were borrowed are more than one year from the date noted.

(7) These series of debt are secured by general mortgage bonds of CenterPoint Houston.

(8) Debt acquired in business acquisitions is adjusted to fair market value as of the acquisition date. Included in long-term debt is additional unamortized premium related to fair value adjustments of long-term debt of $3 million at both December 31, 2007 and 2008, which is being amortized over the respective remaining term of the related long-term debt.

(a) Short-term Borrowings

Receivables Facility. On November 25, 2008, CERC replaced a receivables facility that had terminated on October 28, 2008 with a new 364-day receivables facility. Availability under the new facility ranges from $128 million to $375 million, reflecting seasonal changes in receivables balances. At December 31, 2007 and 2008 the facility size was $300 and $128 million, respectively. As of December 31, 2007 and 2008, advances under the receivables facilities were $232 million and $78 million, respectively. As of December 31, 2008, advances had an interest rate of 3.81%.

Inventory Financing. In December 2008, CERC entered into an asset management agreement whereby it sold $110 million of its natural gas in storage and agreed to repurchase an equivalent amount of natural gas during the 2008-2009 winter heating season for payments totaling $114 million. This transaction was accounted for as a financing and, as of December 31, 2008, the Company's financial statements reflect natural gas inventory of $75 million and a financing obligation of $75 million related to this transaction.

Revolving Credit Facility. In November 2008, CenterPoint Houston entered into a $600 million 364-day credit facility. The $600 million CenterPoint Houston credit facility will terminate if bonds are issued to securitize the costs incurred as a result of Hurricane Ike and if those bonds are issued prior to the November 24, 2009 expiration of the facility. CenterPoint Houston expects to seek legislative and regulatory approval for the issuance of such bonds during 2009.

The $600 million CenterPoint Houston credit facility is secured by a pledge of $600 million of general mortgage bonds issued by CenterPoint Houston. Borrowing costs for London Interbank Offered Rate (LIBOR)-based loans will be at a margin of 2.25 percent above LIBOR rates, based on CenterPoint Houston's current ratings. In addition, CenterPoint Houston will pay lenders, based on current ratings, a per annum commitment fee of 0.5 percent for their commitments under the facility and a quarterly duration fee of 0.75 percent on the average amount of outstanding borrowings during the quarter. The spread to LIBOR and the commitment fee fluctuate based on the borrower's credit rating. The facility contains covenants, including a debt (excluding transition and other securitization bonds) to total capitalization covenant. As of December 31, 2008, there were no borrowings outstanding under the $600 million CenterPoint Houston credit facility.

(b) Long-term Debt

Senior Notes and General Mortgage Bonds. In May 2008, the Company issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.50%. The proceeds from the sale of the senior notes were used for general corporate purposes, including the satisfaction of cash payment obligations in connection with conversions of the Company's 3.75% convertible senior notes.

In May 2008, CERC Corp. issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.00%. The proceeds from the sale of the senior notes were used for general corporate purposes, including capital expenditures, working capital and loans to or investments in affiliates.

In January 2009, CenterPoint Houston issued $500 million aggregate principal amount of general mortgage bonds, due in March 2014 with an interest rate of 7.00%. The proceeds from the sale of the bonds were used for general corporate purposes, including the repayment of outstanding borrowings under its revolving credit facility and the money pool, capital expenditures and storm restoration costs associated with Hurricane Ike.

Revolving Credit Facilities. The Company's $1.2 billion credit facility has a first-drawn cost of LIBOR plus 55 basis points based on the Company's current credit ratings. The facility contains a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant, which was modified (i) in August 2008 so that the permitted ratio of debt to EBITDA would continue at its then-current level for the remaining term of the facility and (ii) in November 2008 so that the permitted ratio of debt to EBITDA would be temporarily increased until the earlier of December 31, 2009 or CenterPoint Houston's issuance of bonds to securitize the costs incurred as a result of Hurricane Ike, after which time the permitted ratio would revert to the level that existed prior to the November 2008 modification.

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

CERC Corp.'s $950 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.

Under the Company's $1.2 billion credit facility, CenterPoint Houston's $289 million credit facility and CERC Corp's $950 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.

As of December 31, 2007 and 2008, the following loan balances were outstanding under the Company's revolving credit facilities (in millions):

	December 31, 2007	December 31, 2008
CenterPoint Energy $1.2 billion credit facility borrowings	$ 131	$ 264
CenterPoint Houston $289 million credit facility borrowings	50	251
CERC Corp. $950 million credit facility borrowings	150	926
Total credit facility borrowings	$ 331	$ 1,441

In addition, as of December 31, 2007 and 2008, the Company had approximately $28 million and $27 million, respectively, of outstanding letters of credit under its $1.2 billion credit facility and CenterPoint Houston had approximately $4 million of outstanding letters of credit under its $289 million credit facility as of both December 31, 2007 and 2008. There was no commercial paper outstanding that would have been backstopped by the Company's $1.2 billion credit facility or CERC Corp.'s $950 million credit facility at December 31, 2007 and 2008. The Company, CenterPoint Houston and CERC Corp. were in compliance with all debt covenants as of December 31, 2008.

Transition Bonds. Pursuant to a financing order issued by the Texas Utility Commission in September 2007, in February 2008 a subsidiary of CenterPoint Houston issued approximately $488 million in 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. Scheduled final payment dates are February 2017 and February 2020. Through issuance of the transition bonds, CenterPoint Houston securitized transition property of approximately $483 million representing the remaining balance of the CTC less an environmental refund as reduced by the fuel reconciliation settlement amount. See Note 3(b) for further discussion.

Convertible Debt. On May 19, 2003, the Company issued $575 million aggregate principal amount of convertible senior notes due May 15, 2023 with an interest rate of 3.75%.

In the fourth quarter of 2007, holders of the Company's 3.75% convertible senior notes converted approximately $40 million principal amount of such notes. Substantially all of such conversions were settled with a cash payment for the principal amount and delivery of 1.3 million shares of the Company's common stock for the excess value due converting holders.

In April 2008, the Company called its 3.75% convertible senior notes for redemption on May 30, 2008. At the time of the announcement, the notes were convertible at the option of the holders, and substantially all of the notes were submitted for conversion on or prior to the May 30, 2008 redemption date. During the year ended December 31, 2008, the Company issued 16.9 million shares of its common stock and paid cash of approximately $532 million to settle conversions of approximately $535 million principal amount of its 3.75% convertible senior notes.

In December 2006, the Company called its 2.875% convertible senior notes for redemption on January 22, 2007. The 2.875% convertible senior notes became immediately convertible at the option of the holders upon the call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% convertible senior notes were converted in January 2007.

The $255 million principal amount of the 2.875% convertible senior notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of the Company's common stock.

Purchase of Pollution Control Bonds. In April 2008, the Company purchased $175 million principal amount of pollution control bonds issued on its behalf at 102% of their principal amount. Prior to the purchase, $100 million principal amount of such bonds had a fixed rate of interest of 7.75% and $75 million principal amount of such bonds had a fixed rate of interest of 8%. Depending on market conditions, the Company may remarket both series of bonds, at 100% of their principal amounts, in 2009.

Maturities. The Company's maturities of long-term debt, capital leases and sinking fund requirements, excluding the ZENS obligation, are $216 million in 2009, $438 million in 2010, $815 million in 2011, $1.8 billion in 2012 and $1.5 billion in 2013.

Liens. As of December 31, 2008, CenterPoint Houston's assets were subject to liens securing approximately $253 million of first mortgage bonds. Sinking or improvement fund and replacement fund requirements on the first mortgage bonds may be satisfied by certification of property additions. Sinking fund and replacement fund requirements for 2006, 2007 and 2008 have been satisfied by certification of property additions. The replacement fund requirement to be satisfied in 2009 is approximately $170 million, and the sinking fund requirement to be satisfied in 2009 is approximately $3 million. The Company expects CenterPoint Houston to meet these 2009 obligations by certification of property additions. As of December 31, 2008, CenterPoint Houston's assets were also subject to liens securing approximately $2.6 billion of general mortgage bonds which are junior to the liens of the first mortgage bonds.

(9) Income Taxes

The components of the Company's income tax expense (benefit) were as follows:

	Year Ended December 31,		
	2006	2007	2008
		(In millions)	
Current:			
Federal	$ 373	$ 163	$ (220)
State	37	32	11
Total current	410	195	(209)
Deferred:			
Federal	(362)	47	437
State	14	(47)	50
Total deferred	(348)	—	487
Income tax expense	$ 62	$ 195	$ 278

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	Year Ended December 31,		
	2006	2007	2008
		(In millions)	
Income before income taxes	$ 494	$ 594	$ 725
Federal statutory rate	35%	35%	35%
Income taxes at statutory rate	173	208	254
Net addition (reduction) in taxes resulting from:			
State income taxes (benefit), net of valuation allowance and federal income tax	33	(10)	40
Amortization of investment tax credit	(7)	(8)	(7)
Tax basis balance sheet adjustments	—	25	—
Increase (decrease) in settled and uncertain income tax positions	(118)	(20)	8
Other, net	(19)	—	(17)
Total	(111)	(13)	24
Income tax expense	$ 62	$ 195	$ 278
Effective income tax rate	12.6%	32.8%	38.4%

Changes in the Texas State Franchise Tax Law (Texas margin tax) resulted in classifying Texas margin tax of approximately $8 million, net of federal income tax effect, as income tax expense in 2008 for CenterPoint Houston. The 2007 state income tax benefit of $10 million includes a benefit of approximately $30 million, net of federal income tax effect, as a result of the Texas margin tax and a Texas state tax examination for the tax years 2002 through 2004.

The tax effects of temporary differences that give rise to significant portions of deferred tax assets and liabilities were as follows:

	December 31,	
	2007	2008
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 17	$ 15
Deferred gas costs	26	13
Other	—	1
Total current deferred tax assets	43	29
Non-current:		
Loss and credit carryforwards	52	36
Employee benefits	173	360
Other	6	57
Total non-current deferred tax assets before valuation allowance	231	453
Valuation allowance	(18)	(5)
Total non-current deferred tax assets	213	448
Total deferred tax assets, net	256	477
Deferred tax liabilities:		
Current:		
Unrealized gain on indexed debt securities	294	373
Unrealized gain on TW Common	77	28
Other	22	—
Total current deferred tax liabilities	393	401
Non-current:		
Depreciation	1,359	1,679
Regulatory assets, net	1,039	1,319
Other	50	59
Total non-current deferred tax liabilities	2,448	3,057
Total deferred tax liabilities	2,841	3,458
Accumulated deferred income taxes, net	$ 2,585	$ 2,981

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2008, the Company has approximately $138 million of state net operating loss carryforwards which expire in various years between 2009 and 2028. A valuation allowance has been established for approximately $60 million of the state net operating loss carryforwards that may not be realized. The Company has a state tax credit carryforward of approximately $44 million which expires in 2026. At December 31, 2008, the Company has approximately $244 million of state capital loss carryforwards which expire in 2017 for which a valuation allowance has been established.

Uncertain Income Tax Positions. The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the adoption of FIN 48, the Company recognized a decrease of approximately $2 million in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 accumulated deficit. A reconciliation of the change in unrecognized tax benefits for 2007 and 2008 is as follows:

	December 31,	
	2007	2008
	(In millions)	
Balance, beginning of year	$ 72	$ 82
Tax positions related to prior years:		
Additions	28	20
Reductions	(20)	(2)
Tax positions related to current year:		
Additions	4	17
Settlements	(2)	—
Balance, end of year	$ 82	$ 117

The Company has approximately $10 million and $14 million of unrecognized tax benefits that, if recognized, would reduce the effective income tax rate for 2007 and 2008, respectively. The Company recognizes interest and penalties as a component of income tax expense. The Company recognized approximately $3 million and $6 million of interest on uncertain income tax positions during 2007 and 2008, respectively. The Company had accrued $4 million and $10 million of interest on uncertain income tax positions at December 31, 2007 and 2008, respectively. The Company does not expect the amount of unrecognized tax benefits to change significantly over the next 12 months.

Tax Audits and Settlements. The Company's consolidated federal income tax returns have been audited and settled through the 2003 tax year. The Company is currently under examination by the IRS for tax years 2004 through 2007 and is at various stages of the examination process. The Company has considered the effects of these examinations in its accrual for settled issues and liability for uncertain income tax positions as of December 31, 2008.

In the fourth quarter of 2006, the Company reached a final settlement with the IRS on the ACES and ZENS issues and executed a closing agreement on the ZENS resulting in a net reduction in income tax expense in 2006 of approximately $92 million. The Company also reached a tentative settlement on other tax issues, including those related to prior acquisitions and dispositions, resulting in a reduction in income tax expense for 2006 of approximately $26 million.

(10) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to the Company's Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, which have various quantity requirements and durations, that are not classified as non-trading derivative assets and liabilities in the Company's Consolidated Balance Sheets as of December 31, 2007 and December 31, 2008 as these contracts meet the SFAS No. 133 exception to be classified as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas supply commitments also include natural gas transportation contracts that do not meet the definition of a derivative. As of December 31, 2008, minimum payment obligations for natural gas supply commitments are approximately $776 million in 2009, $474 million in 2010, $437 million in 2011, $430 million in 2012, $447 million in 2013 and $956 million in 2014 and thereafter.

(b) Lease Commitments

The following table sets forth information concerning the Company's obligations under non-cancelable long-term operating leases at December 31, 2008, which primarily consist of rental agreements for building space, data processing equipment and vehicles (in millions):

2009	$	14
2010		12
2011		11
2012		7
2013		6
2014 and beyond		25
Total	$	75

Total lease expense for all operating leases was $56 million, $48 million and $46 million during 2006, 2007 and 2008, respectively.

(c) Other Commitments

In December 2008, the Company entered into an agreement to purchase software licenses, support and maintenance over the next five years. As of December 31, 2008, payment obligations under this agreement are $5 million in 2009, $7 million in 2010, $6 million in 2011, $6 million in 2012 and $6 million in 2013.

In 2007, CenterPoint Energy Gas Transmission Company (CEGT) completed phases one and two of its Carthage to Perryville pipeline project with a total capacity of 1.25 billion cubic feet (Bcf) per day. In 2008, CEGT completed the Phase III expansion of the Carthage to Perryville pipeline which increased total capacity to 1.5 Bcf per day. During the four-year period subsequent to the in-service date of the pipeline, XTO Energy, CEGT's anchor shipper, can request, and subject to mutual negotiations that meet specific financial parameters and to FERC approval, CEGT would construct a 67-mile extension from CEGT's Perryville hub to an interconnect with Texas Eastern Gas Transmission at Union Church, Mississippi. CEGT filed with FERC on December 5, 2008 to increase the Carthage to Perryville capacity to approximately 1.9 Bcf per day. The expansion includes a new compressor unit at two of CEGT's existing stations and is currently projected to be placed in service in the second quarter of 2010.

(d) Legal, Environmental and Other Regulatory Matters

Legal Matters

RRI Indemnified Litigation

The Company, CenterPoint Houston or their predecessor, Reliant Energy, Incorporated (Reliant Energy), and certain of their former subsidiaries are named as defendants in several lawsuits described below. Under a master separation agreement between the Company and Reliant Energy, Inc. (formerly Reliant Resources, Inc.) (RRI), the Company and its subsidiaries are entitled to be indemnified by RRI for any losses, including attorneys' fees and other costs, arising out of the lawsuits described below under "Gas Market Manipulation Cases," and "Electricity Market Manipulation Cases." Pursuant to the indemnification obligation, RRI is defending the Company and its subsidiaries to the extent named in these lawsuits. Although the ultimate outcome of these matters cannot be predicted at this time, the Company has not considered it necessary to establish reserves related to this litigation.

Gas Market Manipulation Cases. A large number of lawsuits were filed against numerous gas market participants in a number of federal and western state courts in connection with the operation of the natural gas markets in 2000-2001. The Company's former affiliate, RRI, was a participant in gas trading in the California and Western markets. These lawsuits, many of which have been filed as class actions, allege violations of state and federal antitrust laws. Plaintiffs in these lawsuits are seeking a variety of forms of relief, including, among others, recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages, full consideration damages and attorneys' fees. The Company and/or Reliant Energy were named in approximately 30 of these lawsuits, which were instituted between 2003 and 2007. In October 2006, RRI reached a settlement of 11 class action natural gas cases pending in state court in California. The court approved this settlement in June 2007. In the other gas cases consolidated in state court in California, the Court of Appeals found that the Company was not a successor to the liabilities of a subsidiary of RRI, and the Company was dismissed from these suits in April 2008. In the Nevada federal litigation, three of the complaints were dismissed based on defendants' filed rate doctrine defense, but the Ninth Circuit Court of Appeals reversed those dismissals and remanded the cases back to the district court for further proceedings. In July 2008, the plaintiffs in four of the federal court cases agreed to dismiss the Company from those cases. In August 2008, the plaintiffs in five additional cases also agreed to dismiss the Company from those cases, but one of these plaintiffs has moved to amend its complaint to add CenterPoint Energy Services, Inc., a subsidiary of CERC Corp., as a defendant in that case. As a result, the Company remains a party in only two remaining gas market manipulation cases, one pending in Nevada state court in Clark County and one in federal district court in Nevada. The Company believes it is not a proper defendant in the remaining cases and will continue to pursue dismissal from those cases.

Electricity Market Manipulation Cases. A large number of lawsuits were filed against numerous market participants in connection with the operation of the California electricity markets in 2000-2001. The Company's former affiliate, RRI, was a participant in the California markets, owning generating plants in the state and participating in both electricity and natural gas trading in that state and in western power markets generally. The Company was named as a defendant in certain of these suits. These lawsuits, many of which were filed as class actions and which were based on a number of legal theories, have all been resolved. In August 2005, RRI reached a settlement with the Federal Energy Regulatory Commission (FERC) enforcement staff, the states of California, Washington and Oregon, California's three largest investor-owned utilities, classes of consumers from California and other western states, and a number of California city and county government entities that resolves their claims against RRI related to the operation of the electricity markets in California and certain other western states in 2000-2001, including the claims made by plaintiffs in the suits against RRI naming the Company. The settlement was approved by the FERC, by the California Public Utilities Commission and by the courts in which the electricity class action cases were pending. An appeal by two parties to the California Court of Appeals was denied with no further appeal sought. A party in the FERC proceedings sought review of the FERC's order approving the settlement in the Ninth Circuit Court of Appeals, but in December 2008, that party voluntarily withdrew its petition for review, and the settlement is now final. The Company is not a party to the settlement, but may rely on the settlement as a defense to any claims.

Other Legal Matters

Natural Gas Measurement Lawsuits. CERC Corp. and certain of its subsidiaries are defendants in a lawsuit filed in 1997 under the Federal False Claims Act alleging mismeasurement of natural gas produced from federal and Indian lands. The suit seeks undisclosed damages, along with statutory penalties, interest, costs and fees. The complaint is part of a larger series of complaints filed against 77 natural gas pipelines and their subsidiaries and affiliates. An earlier single action making substantially similar allegations against the pipelines was dismissed by the federal district court for the District of Columbia on grounds of improper joinder and lack of jurisdiction. As a result, the various individual complaints were filed in numerous courts throughout the country. This case has been consolidated, together with the other similar False Claims Act cases, in the federal district court in Cheyenne, Wyoming. In October 2006, the judge considering this matter granted the defendants' motion to dismiss the suit on the ground that the court lacked subject matter jurisdiction over the claims asserted. The plaintiff has sought review of that dismissal from the Tenth Circuit Court of Appeals, where the matter remains pending.

In addition, CERC Corp. and certain of its subsidiaries are defendants in two mismeasurement lawsuits brought against approximately 245 pipeline companies and their affiliates pending in state court in Stevens County, Kansas. In one case (originally filed in May 1999 and amended four times), the plaintiffs purport to represent a class of royalty owners who allege that the defendants have engaged in systematic mismeasurement of the volume of natural gas for more than 25 years. The plaintiffs amended their petition in this suit in July 2003 in response to an order from the judge denying certification of the plaintiffs' alleged class. In the amendment the plaintiffs dismissed their claims against certain defendants (including two CERC Corp. subsidiaries), limited the scope of the class of plaintiffs they purport to represent and eliminated previously asserted claims based on mismeasurement of the British thermal unit (Btu) content of the gas. The same plaintiffs then filed a second lawsuit, again as representatives of a putative class of royalty owners, in which they assert their claims that the defendants have engaged in systematic mismeasurement of the Btu content of natural gas for more than 25 years. In both lawsuits, the plaintiffs seek compensatory damages, along with statutory penalties, treble damages, interest, costs and fees. CERC believes that there has been no systematic mismeasurement of gas and that the lawsuits are without merit. CERC does not expect the ultimate outcome of the lawsuits to have a material impact on the financial condition, results of operations or cash flows of either the Company or CERC.

Gas Cost Recovery Litigation. In October 2002, a lawsuit was filed on behalf of certain CERC ratepayers in state district court in Wharton County, Texas against the Company, CERC Corp., Entex Gas Marketing Company (EGMC), and certain non-affiliated companies alleging fraud, violations of the Texas Deceptive Trade Practices Act, violations of the Texas Utilities Code, civil conspiracy and violations of the Texas Free Enterprise and Antitrust Act with respect to rates charged to certain consumers of natural gas in the State of Texas. The plaintiffs initially sought certification of a class of Texas ratepayers, but subsequently dropped their request for class certification. The plaintiffs later added as defendants CenterPoint Energy Marketing Inc., CenterPoint Energy Pipeline Services, Inc. (CEPS), and certain other subsidiaries of CERC, and other non-affiliated companies. In February 2005, the case was removed to federal district court in Houston, Texas, and in March 2005, the plaintiffs voluntarily dismissed the case and agreed not to refile the claims asserted unless the Miller County case described below is not certified as a class action or is later decertified.

In October 2004, a lawsuit was filed by certain CERC ratepayers in Texas and Arkansas in circuit court in Miller County, Arkansas against the Company, CERC Corp., EGMC, CenterPoint Energy Gas Transmission Company (CEGT), CenterPoint Energy Field Services (CEFS), CEPS, Mississippi River Transmission Corp. (MRT) and various non-affiliated companies alleging fraud, unjust enrichment and civil conspiracy with respect to rates charged to certain consumers of natural gas in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. Subsequently, the plaintiffs dropped CEGT and MRT as defendants. Although the plaintiffs in the Miller County case sought class certification, no class was certified. In June 2007, the Arkansas Supreme Court determined that the Arkansas claims were within the sole and exclusive jurisdiction of the Arkansas Public Service Commission (APSC). In response to that ruling, in August 2007 the Miller County court stayed but refused to dismiss the Arkansas claims. In February 2008, the Arkansas Supreme Court directed the Miller County court to dismiss the entire case for lack of jurisdiction. The Miller County court subsequently dismissed the case in accordance with the Arkansas Supreme Court's mandate and all appellate deadlines have expired.

In June 2007, the Company, CERC Corp., EGMC and other defendants in the Miller County case filed a petition in a district court in Travis County, Texas seeking a determination that the Railroad Commission has exclusive original jurisdiction over the Texas claims asserted in the Miller County case. In October 2007, CEFS and CEPS joined the petition in the Travis County case. In October 2008, the district court ruled that the Railroad Commission had exclusive original jurisdiction over the Texas claims asserted against the Company, CERC Corp., EGMC and the other defendants in the Miller County case. In January 2009, the court entered a final declaratory judgment ruling that the Railroad Commission has exclusive jurisdiction over Texas claims. The Company does not anticipate that an appeal will be filed.

In August 2007, the Arkansas plaintiff in the Miller County litigation initiated a complaint at the APSC seeking a decision concerning the extent of the APSC's jurisdiction over the Miller County case and an investigation into the merits of the allegations asserted in his complaint with respect to CERC. In February 2009, the Arkansas plaintiff notified the APSC that he would no longer pursue his claims. That complaint remains pending at the APSC, subject to the review of the Arkansas Attorney General, APSC Staff and the APSC.

In February 2003, a lawsuit was filed in state court in Caddo Parish, Louisiana against CERC with respect to rates charged to a purported class of certain consumers of natural gas and gas service in the State of Louisiana. In February 2004, another suit was filed in state court in Calcasieu Parish, Louisiana against CERC seeking to recover alleged overcharges for gas or gas services allegedly provided by CERC to a purported class of certain consumers of natural gas and gas service without advance approval by the Louisiana Public Service Commission (LPSC). At the time of the filing of each of the Caddo and Calcasieu Parish cases, the plaintiffs in those cases filed petitions with the LPSC relating to the same alleged rate overcharges. The Caddo and Calcasieu Parish lawsuits were stayed pending the resolution of the petitions filed with the LPSC. In August 2007, the LPSC issued an order approving a Stipulated Settlement in the review initiated by the plaintiffs in the Calcasieu Parish litigation. In the LPSC proceeding, CERC's gas purchases were reviewed back to 1971. The review concluded that CERC's gas costs were “reasonable and prudent,” but CERC agreed to credit to jurisdictional customers approximately $920,000, including interest, related to certain off-system sales. The refund was completed in the fourth quarter of 2008. A similar review by the LPSC related to the Caddo Parish litigation was resolved without additional payment by CERC. In October 2008, the courts considering the Caddo and Calcasieu Parish cases dismissed these cases pursuant to motions to dismiss and these proceedings have been concluded.

Storage Facility Litigation. In February 2007, an Oklahoma district court in Coal County, Oklahoma, granted a summary judgment against CEGT in a case, Deka Exploration, Inc. v. CenterPoint Energy, filed by holders of oil and gas leaseholds and some mineral interest owners in lands underlying CEGT’s Chiles Dome Storage Facility. The dispute concerns “native gas” that may have been in the Wapanucka formation underlying the Chiles Dome facility when that facility was constructed in 1979 by a CERC entity that was the predecessor in interest of CEGT. The court ruled that the plaintiffs own native gas underlying those lands, since neither CEGT nor its predecessors had condemned those ownership interests. The court rejected CEGT’s contention that the claim should be barred by the statute of limitations, since the suit was filed over 25 years after the facility was constructed. The court also rejected CEGT’s contention that the suit is an impermissible attack on the determinations the FERC and Oklahoma Corporation Commission made regarding the absence of native gas in the lands when the facility was constructed. The summary judgment ruling was only on the issue of liability, though the court did rule that CEGT has the burden of proving that any gas in the Wapanucka formation is gas that has been injected and is not native gas. Further hearings and orders of the court are required to specify the appropriate relief for the plaintiffs. CEGT plans to appeal through the Oklahoma court system any judgment that imposes liability on CEGT in this matter. The Company and CERC do not expect the outcome of this matter to have a material impact on the financial condition, results of operations or cash flows of either the Company or CERC.

Environmental Matters

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

At December 31, 2008, CERC had accrued $14 million for remediation of these Minnesota sites and the estimated range of possible remediation costs for these sites was $4 million to $35 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. CERC has utilized an environmental expense tracker mechanism in its rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2008, CERC had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. CERC has been named as a defendant in a lawsuit filed in the United States District Court, District of Maine, under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of CERC or its divisions. CERC has also been identified as a PRP by the State of Maine for a site that is the subject of the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. The Company is investigating details regarding the site and the range of environmental expenditures for potential remediation. However, CERC believes it is not liable as a former owner or operator of the site under the Comprehensive Environmental, Response, Compensation and Liability Act of 1980, as amended, and applicable state statutes, and is vigorously contesting the suit and its designation as a PRP.

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

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

Groundwater Contamination Litigation. Predecessor entities of CERC, along with several other entities, are defendants in litigation, *St. Michel Plantation, LLC, et al, v. White, et al*., pending in civil district court in Orleans Parish, Louisiana. In the lawsuit, the plaintiffs allege that their property in Terrebonne Parish, Louisiana suffered salt water contamination as a result of oil and gas drilling activities conducted by the defendants. Although a predecessor of CERC held an interest in two oil and gas leases on a portion of the property at issue, neither it nor any other CERC entities drilled or conducted other oil and gas operations on those leases. In January 2009, CERC and the plaintiffs reached agreement on the terms of a settlement that, if ultimately approved by the Louisiana Department of Natural Resources and the court, is expected to finally resolve this litigation. The Company 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 the Company or CERC.

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

Other Proceedings

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

Guaranties

Prior to the Company's distribution of its ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI's trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for CERC's benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, the Company, CERC and RRI amended that agreement and CERC released the letters of credit it held as security. Under the revised agreement RRI agreed to provide cash or new letters of credit to secure CERC against exposure under the remaining guaranties as calculated under the new agreement if and to the extent changes in market conditions exposed CERC to a risk of loss on those guaranties.

The potential exposure to CERC under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under these transportation contracts, which will be effective until 2018, was approximately $108 million as of December 31, 2008. RRI continues to meet its obligations under the contracts, and, on the basis of market conditions, the Company and CERC have not required additional security. However, if RRI should fail to perform its obligations under the contracts or if RRI should fail to provide adequate security in the event market conditions change adversely, the Company would retain exposure to the counterparty under the guaranty.

(11) Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents, investments in debt and equity securities classified as "available-for-sale" and "trading" in accordance with SFAS No. 115, and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair values of non-trading derivative assets and liabilities are equivalent to their carrying amounts in the Consolidated Balance Sheets at December 31, 2007 and 2008 and have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques (see Notes 4 and 5). Therefore, these financial instruments are stated at fair value and are excluded from the table below.

	December 31, 2007		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Financial liabilities:				
Long-term debt (excluding capital leases)	$ 9,564	$ 10,048	$ 10,396	$ 9,875

(12) Earnings Per Share

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

	For the Year Ended December 31,		
	2006	2007	2008
	(In millions, except per share and share amounts)		
Basic earnings per share calculation:			
Net income	$ 432	$ 399	$ 447
Weighted average shares outstanding	311,826,000	320,480,000	336,387,000
Basic earnings per share	$ 1.39	$ 1.25	$ 1.33
Diluted earnings per share calculation:			
Net income	$ 432	$ 399	$ 447
Weighted average shares outstanding	311,826,000	320,480,000	336,387,000
Plus: Incremental shares from assumed conversions:			
Stock options(1)	974,000	1,059,000	760,000
Restricted stock	1,553,000	1,928,000	1,772,000
2.875% convertible senior notes	1,625,000	291,000	—
3.75% convertible senior notes	8,800,000	18,749,000	4,636,000
Weighted average shares assuming dilution	324,778,000	342,507,000	343,555,000
Diluted earnings per share	$ 1.33	$ 1.17	$ 1.30

(1) Options to purchase 5,863,907, 3,225,969 and 2,617,772 shares were outstanding for the years ended December 31, 2006, 2007 and 2008, respectively, but were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares for the respective years.

All of the 2.875% contingently convertible senior notes and substantially all of the 3.75% contingently convertible senior notes provided for settlement of the principal portion in cash rather than stock. In accordance with Emerging Issues Task Force Issue No. 04-8, "Accounting Issues related to Certain Features of Contingently Convertible Debt and the Effect on Diluted Earnings Per Share," the portion of the conversion value of such notes that must be settled in cash rather than stock is excluded from the computation of diluted earnings per share from continuing operations. The Company included the conversion spread in the calculation of diluted earnings per share when the average market price of the Company's common stock in the respective reporting period exceeded the conversion price. All of the Company's 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007 and substantially all of the Company's 3.75% convertible senior notes were submitted for conversion on or prior to the May 30, 2008 redemption date, as described in Note 8(b), "Long-term Debt — Convertible Debt."

(13) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2007			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Revenues	$ 3,106	$ 2,033	$ 1,882	$ 2,602
Operating income	353	242	287	303
Net income	130	70	91	108
Basic earnings per share(1)	$ 0.41	$ 0.22	$ 0.29	$ 0.34
Diluted earnings per share(1)	$ 0.38	$ 0.20	$ 0.27	$ 0.32

	Year Ended December 31, 2008			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Revenues	$ 3,363	$ 2,670	$ 2,515	$ 2,774
Operating income	336	297	337	303
Net income	123	101	136	87
Basic earnings per share(1)	$ 0.38	$ 0.30	$ 0.40	$ 0.25
Diluted earnings per share(1)	$ 0.36	$ 0.30	$ 0.39	$ 0.25

(1) Quarterly earnings per common share are based on the weighted average number of shares outstanding during the quarter, and the sum of the quarters may not equal annual earnings per common share. The Company included the conversion spread related to its contingently convertible senior notes in the calculation of diluted earnings per share when the average market price of the Company's common stock in the respective reporting period exceeds the conversion price. All of the Company's 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007 and substantially all of the Company's 3.75% convertible senior notes were submitted for conversion on or prior to the May 30, 2008 redemption date, as described in Note 8(b), "Long-term Debt — Convertible Debt."

(14) Reportable Business Segments

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

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

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

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

	Revenues from External Customers	Intersegment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2006:						
Electric Transmission & Distribution	$ 1,781(1)	$ —	$ 379	$ 576	$ 8,463	$ 389
Natural Gas Distribution	3,582	11	152	124	4,463	187
Competitive Natural Gas Sales and Services	3,572	79	1	77	1,501	18
Interstate Pipelines(2)	255	133	37	181	2,738	437
Field Services(3)	119	31	10	89	608	65
Other	10	5	20	(2)	2,047(4)	25
Reconciling Eliminations	—	(259)	—	—	(2,187)	—
Consolidated	$ 9,319	$ —	$ 599	$ 1,045	$ 17,633	$ 1,121
As of and for the year ended December 31, 2007:						
Electric Transmission & Distribution	$ 1,837(1)	$ —	$ 398	$ 561	$ 8,358	$ 401
Natural Gas Distribution	3,749	10	155	218	4,332	191
Competitive Natural Gas Sales and Services	3,534	45	5	75	1,221	7
Interstate Pipelines(2)	357	143	44	237	3,007	308
Field Services(3)	136	39	11	99	669	74
Other	10	—	18	(5)	1,956(4)	30
Reconciling Eliminations	—	(237)	—	—	(1,671)	—
Consolidated	$ 9,623	$ —	$ 631	$ 1,185	$ 17,872	$ 1,011
As of and for the year ended December 31, 2008:						
Electric Transmission & Distribution	$ 1,916(1)	$ —	$ 460	$ 545	$ 8,880	$ 481(5)
Natural Gas Distribution	4,217	9	157	215	4,961	214
Competitive Natural Gas Sales and Services	4,488	40	3	62	1,315	8
Interstate Pipelines(2)	477	173	46	293	3,578	189
Field Services(3)	213	39	12	147	826	122
Other	11	—	30	11	2,185(4)	39
Reconciling Eliminations	—	(261)	—	—	(2,069)	—
Consolidated	$ 11,322	$ —	$ 708	$ 1,273	$ 19,676	$ 1,053

(1) Sales to subsidiaries of RRI in 2006, 2007 and 2008 represented approximately $737 million, $661 million and $635 million, respectively, of CenterPoint Houston's transmission and distribution revenues.

(2) Interstate Pipelines recorded equity income of $6 million and $36 million (including $6 million and $33 million related to pre-operating allowance for funds used during construction) in the years ended December 31, 2007 and 2008, respectively, from its 50 percent interest in SESH, a jointly-owned pipeline.

These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Interstate Pipelines' investment in SESH was $8 million, $58 million and $307 million as of December 31, 2006, 2007 and 2008 and is included in Investment in unconsolidated affiliates.

(3) Field Services recorded equity income of $6 million, $10 million and $15 million for the years ended December 31, 2006, 2007 and 2008, respectively, from its 50 percent interest in a jointly-owned gas processing plant. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Field Services' investment in the jointly-owned gas processing plant was $24 million, $30 million and $38 million as of December 31, 2006, 2007 and 2008 and is included in Investment in unconsolidated affiliates.

(4) Included in total assets of Other Operations as of December 31, 2006 and 2007 are pension assets of $109 million and $231 million, respectively. Also included in total assets of Other Operations as of December 31, 2006, 2007 and 2008, are pension related regulatory assets of $420 million, $319 million and $800 million, respectively, resulting from the Company's adoption of SFAS No. 158.

(5) Included in expenditures for long-lived assets of Electric Transmission & Distribution is $145 million related to Hurricane Ike.

	Year Ended December 31,		
Revenues by Products and Services:	**2006**	**2007**	**2008**
		(In millions)	
Electric delivery sales	$ 1,781	$ 1,837	$ 1,916
Retail gas sales	4,546	4,941	6,216
Wholesale gas sales	2,331	2,196	2,295
Gas transport	550	532	756
Energy products and services	111	117	139
Total	$ 9,319	$ 9,623	$11,322

(15) Subsequent Events

On January 22, 2009, the Company's board of directors declared a regular quarterly cash dividend of $0.19 per share of common stock payable on March 10, 2009, to shareholders of record as of the close of business on February 16, 2009.

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

None.

Item 9A. *Controls and Procedures*

Disclosure Controls And Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2008 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART III

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

The information called for by Item 10, to the extent not set forth in "Executive Officers" in Item 1, will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2009 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 11. *Executive Compensation*

The information called for by Item 11 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2009 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 12 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2009 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 13 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2009 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 14. *Principal Accounting Fees and Services*

The information called for by Item 14 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2009 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) Financial Statements.

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2008.

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

III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits in the Company's Annual Report on Form 10-K for the year ended December 31, 2008 filed with the Securities and Exchange Commission on February 25, 2009, which can be found on the Company's website at www.centerpointenergy.com/investors and at www.sec.gov.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and the Company's internal control over financial reporting as of December 31, 2008, and have issued our reports thereon dated February 25, 2009; such reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules of the Company listed in the index at Item 15 (a)(2). These consolidated financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2009

CENTERPOINT ENERGY, INC.

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

STATEMENTS OF INCOME

	For the Year Ended December 31,		
	2006	2007	2008
		(In millions)	
Expenses:			
Operation and Maintenance Expenses	$ (19)	$ (17)	$ (12)
Taxes Other than Income	(2)	(4)	1
Total	(21)	(21)	(11)
Other Income (Expense):			
Interest Income from Subsidiaries	18	22	12
Other Income (Expense)	6	1	(5)
Gain (Loss) on Indexed Debt Securities	(80)	111	128
Interest Expense to Subsidiaries	(69)	(67)	(38)
Interest Expense	(196)	(219)	(160)
Distribution to ZENS Holders	—	(27)	—
Total	(321)	(179)	(63)
Loss Before Income Taxes	(342)	(200)	(74)
Income Tax Benefit	214	84	31
Loss Before Equity in Subsidiaries	(128)	(116)	(43)
Equity Income of Subsidiaries	560	515	490
Net Income	$ 432	$ 399	$ 447

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

CENTERPOINT ENERGY, INC.

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

BALANCE SHEETS

	December 31, 2007	December 31, 2008
	(In millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ —	$ —
Notes receivable — subsidiaries	216	82
Accounts receivable — subsidiaries	106	53
Other assets	2	—
Total current assets	324	135
Other Assets:		
Investment in subsidiaries	5,848	5,176
Notes receivable — subsidiaries	151	151
Other assets	578	826
Total other assets	6,577	6,153
Total Assets	$ 6,901	$ 6,288
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Notes payable — subsidiaries	$ 1	$ 21
Current portion of long-term debt	849	117
Indexed debt securities derivative	261	133
Accounts payable:		
Subsidiaries	558	40
Other	3	3
Taxes accrued	372	338
Interest accrued	28	26
Non-trading derivative liabilities	2	—
Other	18	18
Total current liabilities	2,092	696
Other Liabilities:		
Accumulated deferred tax liabilities	193	138
Benefit obligations	78	426
Notes payable — subsidiaries	750	750
Other	1	7
Total non-current liabilities	1,022	1,321
Long-Term Debt	1,977	2,234
Shareholders' Equity:		
Common stock	3	3
Additional paid-in capital	3,023	3,135
Accumulated deficit	(1,172)	(970)
Accumulated other comprehensive loss	(44)	(131)
Total shareholders' equity	1,810	2,037
Total Liabilities and Shareholders' Equity	$ 6,901	$ 6,288

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

CENTERPOINT ENERGY, INC.

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

STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
	2006	2007	2008
		(In millions)	
Operating Activities:			
Net income	$ 432	$ 399	$ 447
Non-cash items included in net income:			
Equity income of subsidiaries	(560)	(515)	(490)
Deferred income tax expense	(169)	52	90
Tax and interest reserves reductions related to ZENS and ACES settlement	(107)	—	—
Amortization of debt issuance costs	36	46	6
Loss (gain) on indexed debt securities	80	(111)	(128)
Changes in working capital:			
Accounts receivable/(payable) from subsidiaries, net	33	20	(65)
Accounts payable	(13)	11	—
Other current assets	(1)	—	2
Other current liabilities	117	(50)	(111)
Common stock dividends received from subsidiaries	227	240	746
Other	18	2	(7)
Net cash provided by operating activities	93	94	490
Investing Activities:			
Short-term notes receivable from subsidiaries	69	175	134
Long-term notes receivable from subsidiaries	21	—	—
Net cash provided by investing activities	90	175	134
Financing Activities:			
Long-term revolving credit facility, net	(3)	131	133
Proceeds from long-term debt	—	250	300
Payments on long-term debt	—	(295)	(907)
Debt issuance costs	(3)	(2)	(4)
Common stock dividends paid	(187)	(218)	(246)
Proceeds from issuance of common stock, net	27	22	80
Short-term notes payable to subsidiaries	153	(157)	20
Long-term notes payable to subsidiaries	(171)	—	—
Net cash used in financing activities	(184)	(269)	(624)
Net Decrease in Cash and Cash Equivalents	(1)	—	—
Cash and Cash Equivalents at Beginning of Year	1	—	—
Cash and Cash Equivalents at End of Year	$ —	$ —	$ —

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

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

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

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

(3) *Long-term Debt.* In May 2008, the Company issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.50%. The proceeds from the sale of the senior notes were used for general corporate purposes, including the satisfaction of cash payment obligations in connection with conversions of the Company's 3.75% convertible senior notes.

The Company's $1.2 billion credit facility has a first-drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on the Company's current credit ratings. The facility contains a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant, which was modified (i) in August 2008 so that the permitted ratio of debt to EBITDA would continue at its then-current level for the remaining term of the facility and (ii) in November 2008 so that the permitted ratio of debt to EBITDA would be temporarily increased until the earlier of December 31, 2009 or CenterPoint Houston's issuance of bonds to securitize the costs incurred as a result of Hurricane Ike, after which time the permitted ratio would revert to the level that existed prior to the November 2008 modification.

Under the Company's $1.2 billion 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.

As of December 31, 2008, the Company had $264 million of borrowings and approximately $27 million of outstanding letters of credit under its $1.2 billion credit facility. The Company had no commercial paper outstanding at December 31, 2008. The Company was in compliance with all covenants as of December 31, 2008.

On May 19, 2003, the Company issued $575 million aggregate principal amount of convertible senior notes due May 15, 2023 with an interest rate of 3.75%.

In the fourth quarter of 2007, holders of the Company's 3.75% convertible senior notes converted approximately $40 million principal amount of such notes. Substantially all of such conversions were settled with a cash payment for the principal amount and delivery of 1.3 million shares of the Company's common stock for the excess value due converting holders.

In April 2008, the Company called its 3.75% convertible senior notes for redemption on May 30, 2008. At the time of the announcement, the notes were convertible at the option of the holders, and substantially all of the notes were submitted for conversion on or prior to the May 30, 2008 redemption date. During the year ended December 31, 2008, the Company issued 16.9 million shares of its common stock and paid cash of approximately $532 million to settle conversions of approximately $535 million principal amount of its 3.75% convertible senior notes.

In December 2006, the Company called its 2.875% convertible senior notes for redemption on January 22, 2007. The 2.875% convertible senior notes became immediately convertible at the option of the holders upon the call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% convertible senior notes were converted in January 2007. The $255 million principal amount of the 2.875% convertible senior notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of the Company's common stock.

In April 2008, the Company purchased $175 million principal amount of pollution control bonds issued on its behalf at 102% of their principal amount. Prior to the purchase, $100 million principal amount of such bonds had a fixed rate of interest of 7.75% and $75 million principal amount of such bonds had a fixed rate of interest of 8%. Depending on market conditions, the Company may remarket both series of bonds, at 100% of their principal amounts, in 2009.

The Company's maturities of long-term debt, excluding the ZENS obligation, are $-0- in 2009, $200 million in 2010, $19 million in 2011, $264 million in 2012 and $-0- in 2013.

(4) *Guaranties.* CenterPoint Energy Services, Inc. (CES) provides comprehensive natural gas sales and services to industrial and commercial customers. In order to hedge their exposure to natural gas prices, CES has entered standard purchase and sale agreements with various counterparties. CenterPoint Energy has guaranteed the payment obligations of CES under certain of these agreements, typically for one-year terms. As of December 31, 2008, CenterPoint Energy had guaranteed $15 million under these agreements.

(5) *Investment in Subsidiaries.* During 2008, the Company reduced its payables to subsidiaries, with no net asset restrictions, by $430 million with a corresponding reduction in investment in subsidiaries.

CENTERPOINT ENERGY, INC.

SCHEDULE II — QUALIFYING VALUATION ACCOUNTS
For the Three Years Ended December 31, 2008

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions From Reserves (2)	Balance at End of Period
			(In millions)		
Year Ended December 31, 2008:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 38	$ 54	$ 3	$ 60	$ 35
Deferred tax asset valuation allowance	18	(1)	(12) [(1)]	—	5
Year Ended December 31, 2007:					
Accumulated provisions:					
Uncollectible accounts receivable	33	45	—	40	38
Deferred tax asset valuation allowance	22	(4)	—	—	18
Year Ended December 31, 2006:					
Accumulated provisions:					
Uncollectible accounts receivable	43	35	—	45	33
Deferred tax asset valuation allowance	21	1	—	—	22

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 25th day of February, 2009.

CENTERPOINT ENERGY, INC.
(Registrant)

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 25, 2009.

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

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

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

	2004	2005	2006	2007 (1)	2008 (1)
Income from continuing operations	$ 205	$ 225	$ 432	$ 399	$ 447
Income taxes for continuing operations	139	153	62	195	278
Capitalized interest	(4)	(4)	(10)	(22)	(20)
	340	374	484	572	705
Fixed charges, as defined:					
Interest	777	710	600	626	609
Capitalized interest	4	4	10	22	20
Interest component of rentals charged to operating expense	11	12	19	16	15
Total fixed charges	792	726	629	664	644
Earnings, as defined	$ 1,132	$ 1,100	$ 1,113	$ 1,236	$ 1,349
Ratio of earnings to fixed charges	1.43	1.51	1.77	1.86	2.09

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

BOARD OF DIRECTORS

MILTON CARROLL, 58
Chairman of the Board,
CenterPoint Energy; Chairman and Founder, Instrument Products, Inc., an oilfield equipment manufacturing company

DONALD R. CAMPBELL, 68
Former Chief Financial Officer,
Sanders Morris Harris Group, Inc.,
a NASDAQ-listed regional investment banking firm

DERRILL CODY, 70
Of counsel to the law firm of
Tomlinson & O'Connell, P.C.

O. HOLCOMBE CROSSWELL, 68
President, Griggs Corporation,
a real estate and investment company

MICHAEL P. JOHNSON, 61
Former Senior Vice President
and Chief Administrative Officer,
The Williams Companies, Inc.,
a publicly held natural gas producer, processor and transporter

JANIECE M. LONGORIA, 56
Partner, law firm of Ogden,
Gibson, Broocks & Longoria, L.L.P.

THOMAS F. MADISON, 73
President and Chief Executive Officer,
MLM Partners, a small business consulting and investments company

DAVID M. MCCLANAHAN, 59
President and Chief Executive Officer,
CenterPoint Energy

ROBERT T. O'CONNELL, 70
Business consultant;
former Chief Financial Officer,
General Motors Corporation

SUSAN O. RHENEY, 49
Private investor and former Principal with The Sterling Group, a private financial and investment organization

MICHAEL E. SHANNON, 72
President, MEShannon & Associates, Inc.,
a corporate financial advisory services and investments company

PETER S. WAREING, 57
Co-founder and Partner,
Wareing, Athon & Company,
a private equity firm

SHERMAN M. WOLFF, 68
Former Executive Vice President
and Chief Operating Officer,
Health Care Service Corporation,
a customer-owned health benefits company

EXECUTIVE COMMITTEE

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President and Chief Executive Officer

SCOTT E. ROZZELL, 59
Executive Vice President
General Counsel and Corporate Secretary

THOMAS R. STANDISH, 59
Senior Vice President
and Group President
Regulated Operations

GARY L. WHITLOCK, 59
Executive Vice President
and Chief Financial Officer

OTHER CORPORATE OFFICERS

JEFF W. BONHAM, 46
Vice President
Government Relations

JAMES M. DUMLER, 48
Senior Vice President
Strategic Planning and Business Development

WALTER L. FITZGERALD, 51
Senior Vice President and
Chief Accounting Officer

CAROL R. HELLIKER, 48
Vice President
Deputy General Counsel and
Corporate Compliance Officer

MARC KILBRIDE, 56
Vice President
and Treasurer

CARLA A. KNEIPP, 37
Vice President
Audit Services

FLOYD J. LEBLANC, 49
Vice President
Corporate Communications

RUFUS S. SCOTT, 65
Senior Vice President
Deputy General Counsel and
Assistant Corporate Secretary

C. DEAN WOODS, 57
Vice President
Human Resources

COMPANY LEADERSHIP

C. GREGORY HARPER, 44
Senior Vice President and
Group President
Pipelines and Field Services

WALTER L. FERGUSON, 53
Division Senior Vice President
Pipeline Operations

HUGH G. MADDOX, 62
Division Senior Vice President
Field Services

CYRIL J. ZEBOT, 59
Division Senior Vice President
Pipelines

JOSEPH B. MCGOLDRICK, 55
Division President
Gas Operations

WAYNE D. STINNETT, JR., 58
Division President
CenterPoint Energy Services

TRACY B. BRIDGE, 50
Division Senior Vice President
Support Operations

KENNETH M. MERCADO, 46
Division Senior Vice President
Advanced Metering System Deployment

SCOTT M. PROCHAZKA, 43
Division Senior Vice President
Electric Operations

JOHNNY L. BLAU, 59
Division Senior Vice President
Business Support Services

CENTERPOINT ENERGY

INVESTOR INFORMATION

ANNUAL MEETING

The 2009 Annual Meeting of Shareholders will be held on Thursday, April 23, at 9 a.m. CDT in the CenterPoint Energy Tower auditorium, 1111 Louisiana Street, Houston, Texas. Shareholders who hold shares of CenterPoint Energy as of February 23, 2009, will receive notice of the meeting and will be eligible to vote.

INVESTOR SERVICES

If you have questions about your CenterPoint Energy investor account, please contact us:

In Houston: (713) 207-3060
Toll Free: (800) 231-6406
Fax: (713) 207-3169

Investor services, online tools and a list of publications may be found on the company's Web site at CenterPointEnergy.com/investors.

Investor Services representatives are available from 8 a.m. to 5 p.m. Central time, Monday through Friday to help you with questions about CenterPoint Energy common stock or enrollment in the CenterPoint Energy Investor's Choice Plan.

The Investor's Choice Plan provides easy, inexpensive investment options, including direct purchase and sale of CenterPoint Energy common stock; dividend reinvestment; statement-based accounting and monthly or quarterly automatic investing by electronic transfer. You can become a registered CenterPoint Energy shareholder by making an initial investment of at least $250 through Investor's Choice.

CenterPoint Energy Investor Services serves as transfer agent, registrar and dividend disbursing agent for CenterPoint Energy common stock.

INFORMATION REQUESTS

Call (888) 468-3020 toll free for additional copies of:
2008 Annual Report and Form 10-K
2009 Proxy Statement

DIVIDEND PAYMENTS

Common stock dividends are generally paid quarterly in March, June, September and December. Dividends are subject to declaration by the Board of Directors, who establish the amount of each quarterly common stock dividend and fix record and payment dates.

INSTITUTIONAL INVESTORS

Security analysts and other investment professionals should contact Marianne Paulsen, Director of Investor Relations at (713) 207-6500.

STOCK LISTING

CenterPoint Energy, Inc. common stock is traded under the symbol CNP on the New York and Chicago stock exchanges.

AUDITORS

Independent Registered Public Accounting Firm
Deloitte & Touche LLP, Houston, Texas

CORPORATE OFFICE, STREET ADDRESS

CenterPoint Energy, Inc.
1111 Louisiana Street
Houston, Texas 77002

MAILING ADDRESS

P.O. Box 4567
Houston, Texas 77210-4567
Telephone: (713) 207-1111

WEB ADDRESS

CenterPointEnergy.com

CERTIFICATIONS

CenterPoint Energy has filed the CEO/CFO certifications regarding the quality of the company's public disclosure required to be filed with the SEC as Exhibits 31.1 and 31.2 to its annual report on Form 10-K and to its quarterly reports on Form 10-Q. In addition, following its annual meeting in 2008, CenterPoint Energy submitted its CEO certification to the New York Stock Exchange pursuant to Section 303A.12(a) of the NYSE's Listed Company's Manual.

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