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

Form 10-K

(Mark One)

R **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 1-13265

CenterPoint Energy Resources Corp.
(Exact name of registrant as specified in its charter)

Delaware	**76-0511406**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1111 Louisiana **Houston, Texas 77002**	**(713) 207-1111**
(Address and zip code of principal executive offices)	*(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
6% Convertible Subordinated Debentures due 2012	New York Stock Exchange

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

CenterPoint Energy Resources Corp. meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

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

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 R

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 R 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 the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. R

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

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

The aggregate market value of the common equity held by non-affiliates as of June 30, 2008: None

TABLE OF CONTENTS

We meet the conditions specified in General Instruction I(1)(a) and (b) of Form 10-K and are thereby permitted to use the reduced disclosure format for wholly owned subsidiaries of reporting companies specified therein. Accordingly, we have omitted from this report the information called for by Item 4 (Submission of Matters to a Vote of Security Holders), Item 10 (Directors, Executive Officers, and Corporate Governance), Item 11 (Executive Compensation), Item 12 (Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters) and Item 13 (Certain Relationships and Related Transactions, and Director Independence) of Form 10-K. In lieu of the information called for by Item 6 (Selected Financial Data) and Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) of Form 10-K, we have included, under Item 7, Management's Narrative Analysis of the Results of Operations to explain the reasons for material changes in the amount of revenue and expense items between 2006, 2007 and 2008.

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 own and operate natural gas distribution systems in six states. Subsidiaries of ours own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of ours offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities. References to “we,” “us,” and “our” mean CenterPoint Energy Resources Corp. (CERC Corp., together with our subsidiaries, CERC). We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

Our reportable business segments are Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations.

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 parent company’s 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). Our parent company’s website address is *www.centerpointenergy.com*. Except to the extent explicitly stated herein, documents and information on our parent company’s website are not incorporated by reference herein.

Natural Gas Distribution

Our 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 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, which struck the upper Texas coast in September 2008. 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

We offer 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 CenterPoint Energy's 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

Our pipelines business operates interstate natural gas pipelines with gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. Our 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 Federal Energy Regulatory Commission (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

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

Our 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 unallocated corporate costs and inter-segment eliminations.

Financial Information About Segments

For financial information about our segments, see Note 12 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.

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, CenterPoint Energy filed with the FERC the required notification of its 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 CenterPoint Energy provides services to its subsidiaries through a service company, its service company is not subject to the FERC's service company rules.

State and Local Regulation

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.

Texas. In March 2008, Gas Operations filed a request to change its rates with the Railroad Commission and the 47 cities in its Texas Coast service territory, an area consisting of approximately 230,000 customers in cities and communities on the outskirts of Houston. 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 filed second motions for rehearing on this order. On February 26, 2009, the Railroad Commission denied the second motions on rehearing reaffirming its original decision. In December 2008, Gas Operations implemented the approved rates for the nine TCUC cities and the environs. Cities with settled rates have the opportunity to adopt the rates established by the Railroad Commission or retain the rates agreed in their settlements.

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 PHMSA of the U.S. Department of Transportation 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 our 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, 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 our pipeline and gathering businesses, our 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.

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. We and our predecessors operated manufactured gas plants (MGPs) in the past. In Minnesota, we have completed remediation on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in our Minnesota service territory. We believe that we have no liability with respect to two of these sites.

At December 31, 2008, we 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. We have utilized an environmental expense tracker mechanism in our rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2008, we 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 us or may have been owned by one of our former affiliates. We have 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 ours or our divisions. We have 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 us, would have to contribute to that remediation. We are investigating details regarding the site and the range of environmental expenditures for potential remediation. However, we believe we are not liable as a former owner or operator of the site under CERCLA, and applicable state statutes, and are vigorously contesting the suit and our 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 formerly owned by our predecessors have contained asbestos insulation and other asbestos-containing materials. We or our predecessor companies have been named, along with numerous others, as a defendant in lawsuits filed by certain individuals who claim injury due to exposure to asbestos during work at such formerly owned facilities. We anticipate that additional claims like those received may be asserted in the future. 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 ours, 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 ours held an interest in two oil and gas leases on a portion of the property at issue, neither it nor any other entities of ours drilled or conducted other oil and gas operations on those leases. In January 2009, we 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 do not expect the outcome of this litigation to have a material adverse impact on our financial condition, results of operations or cash flows.

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 4,643 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
Natural Gas Distribution	3,652	1,405
Competitive Natural Gas Sales and Services	122	—
Interstate Pipelines	654	—
Field Services	215	—
Total	4,643	1,405

As of December 31, 2008, approximately 30% of our employees are subject to collective bargaining agreements. One of the collective bargaining agreements covering approximately 9% 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.

Item 1A. *Risk Factors*

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 our business.

Risk Factors Affecting Our Businesses

Rate regulation of our business may delay or deny our ability to earn a reasonable return and fully recover our costs.

Rates for Gas Operations are regulated by certain municipalities and state commissions, and for our interstate pipelines by the FERC, based on an analysis of our invested capital and our expenses in a test year. Thus, the rates that we are allowed to charge may not match our 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 our costs and enable us to earn a reasonable return on our invested capital.

Our businesses must compete with alternate energy sources, which could result in our marketing less natural gas, and our 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 our results of operations, financial condition and cash flows.

We compete 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 us 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 our 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 us as a result of competition may have an adverse impact on our results of operations, financial condition and cash flows.

Our two interstate pipelines and our 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. We also compete indirectly with other forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price. The actions of our competitors could lead to lower prices, which may have an adverse impact on our 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 our results of operations, financial condition and cash flows.

Our 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 our suppliers and customers to meet their obligations or otherwise adversely affect our liquidity and results of operations.

We are subject to risk associated with increases in the price of natural gas. Increases in natural gas prices might affect our ability to collect balances due from our customers and, for Gas Operations, could create the potential for uncollectible accounts expense to exceed the recoverable levels built into our 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 we operate thereby resulting in decreased sales volumes and revenues and (ii) increase the risk that our suppliers or customers fail or are unable to meet their obligations. Additionally, increasing natural gas prices could create the need for us to provide collateral in order to purchase natural gas.

A decline in our credit rating could result in us having to provide collateral in order to purchase gas.

If our credit rating were to decline, we 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 we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations, financial condition and cash flows could be adversely affected.

The revenues and results of operations of our interstate pipelines and field services businesses are subject to fluctuations in the supply and price of natural gas.

Our 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 our results of operations, financial condition and cash flows.

Our 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.

Our revenues and results of operations are seasonal.

A substantial portion of our revenues is derived from natural gas sales and transportation. Thus, our 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 we had planned.

Our subsidiaries 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 our 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 our expected investment return, which could adversely affect our financial condition, results of operations or cash flows.

The states in which we provide 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 our ability to operate.

The Public Utility Holding Company Act of 1935, to which CenterPoint Energy and its 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 we do 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 our ability to operate our utility operations, to finance our 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 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 $3.9 billion of outstanding indebtedness on a consolidated basis. As of December 31, 2008, approximately $723 million principal amount of this debt is required to be paid through 2011. Our future financing activities may be significantly affected by, among other things:

- 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 and CenterPoint Energy's ability to access capital markets on reasonable terms; and
- provisions of relevant tax and securities laws.

Our current credit ratings are discussed in "Management's Narrative Analysis of Results of Operations — Liquidity — 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.

The financial condition and liquidity of our parent company could affect our access to capital, our credit standing and our financial condition.

Our access to credit and credit ratings may be impacted by CenterPoint Energy's credit standing. As of December 31, 2008, CenterPoint Energy and its subsidiaries other than us have approximately $230 million principal amount of debt required to be paid through 2011. This amount excludes amounts related to capital leases, transition bonds and indexed debt securities obligations. We cannot assure you that CenterPoint Energy and its other subsidiaries will be able to pay or refinance these amounts. If CenterPoint Energy were to experience a deterioration in its credit standing or liquidity difficulties, our access to credit and our credit ratings could be adversely affected.

We are an indirect wholly owned subsidiary of CenterPoint Energy. CenterPoint Energy can exercise substantial control over our dividend policy and business and operations and could do so in a manner that is adverse to our interests.

We are managed by officers and employees of CenterPoint Energy. Our management will make determinations with respect to the following:

- our payment of dividends;
- decisions on our financings and our capital raising activities;
- mergers or other business combinations; and

- our acquisition or disposition of assets.

There are no contractual restrictions on our ability to pay dividends to CenterPoint Energy. Our management could decide to increase our dividends to CenterPoint Energy to support its cash needs. This could adversely affect our liquidity. However, under our credit facility and our receivables facility, our ability to pay dividends is restricted by a covenant that debt as a percentage of total capitalization may not exceed 65%.

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.

We derive a substantial portion of our operating income from subsidiaries through which we hold a substantial portion of our assets.

We derive a substantial portion of our operating income from, and hold a substantial portion of our assets through, our subsidiaries. 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.

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, and gas gathering and processing 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.

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

Under some circumstances, we and CenterPoint Energy could incur liabilities associated with assets and businesses we and CenterPoint Energy no longer own.

In connection with the organization and capitalization of Reliant Resources, Inc. (RRI), RRI and its subsidiaries assumed liabilities associated with various assets and businesses Reliant Energy, Incorporated (Reliant Energy) transferred to them. RRI also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, CenterPoint Energy and its subsidiaries, including us, 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 and CenterPoint Energy could be responsible for satisfying the liability.

Prior to CenterPoint Energy’s distribution of its ownership in RRI to its shareholders, we 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 us against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for our benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, we, CenterPoint Energy and RRI amended that agreement and we released the letters of credit we held as security. Under the revised agreement, RRI agreed to provide cash or new letters of credit to secure us against exposure under the remaining guaranties as calculated under the revised agreement if and to the extent changes in market conditions exposed us to a risk of loss on those guaranties.

Our potential exposure 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 CenterPoint Energy 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.

CenterPoint Energy, Reliant Energy, RRI and one of our subsidiaries are named as defendants in a number of lawsuits arising out of the operations of the natural gas markets in 2000-2001. Although these matters relate to the business and operations of RRI, we or CenterPoint Energy could incur liability if claims in one or more of these lawsuits were successfully asserted against us, any of our subsidiaries or CenterPoint Energy and indemnification from RRI were determined to be unavailable or if RRI were unable to satisfy indemnification obligations owed with respect to those claims.

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 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, stopped funding its commitment following the bankruptcy filing of its parent in September 2008. 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 CenterPoint Energy's pension plan in which we participate. These reductions are expected to result in increased 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 our principal properties in fee. Most of our gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

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.

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

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

The information called for by Item 4 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

PART II

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

All of the 1,000 outstanding shares of CERC Corp.'s common stock are held by Utility Holding, LLC, a wholly owned subsidiary of CenterPoint Energy.

In each of 2006, 2007 and 2008, we paid dividends on our common stock of $100 million to Utility Holding, LLC.

Our revolving credit facility limits our debt as a percentage of total capitalization to 65%. This covenant could restrict our ability to distribute dividends.

Item 6. *Selected Financial Data*

The information called for by Item 6 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries). The ratio of earnings to fixed charges as calculated pursuant to Securities and Exchange Commission rules was 2.20, 2.64, 2.67, 3.10 and 3.32 for the years ended December 31, 2004, 2005, 2006, 2007 and 2008, respectively.

Item 7. *Management's Narrative Analysis of Results of Operations*

The following narrative analysis should be read in combination with our consolidated financial statements and notes contained in Item 8 of this report.

Background

We own and operate natural gas distribution systems in six states. Subsidiaries of ours own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of ours offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities. We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy).

Business Segments

Because we are an indirect wholly owned subsidiary of CenterPoint Energy, our determination of reportable segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. In this section, we discuss our results on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. 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 natural gas distribution services and interstate pipelines are subject to rate regulation. A summary of our reportable business segments as of December 31, 2008 is set forth below:

Natural Gas Distribution

We own and operate 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

Our 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

Our 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. We also own and operate 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. 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 million cubic feet per day of deliverability. Most storage operations are in north Louisiana and Oklahoma.

Field Services

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.

Other Operations

Our other operations business segment includes unallocated corporate costs and inter-segment eliminations.

EXECUTIVE SUMMARY

Significant Events in 2008 and 2009

Hurricane Ike

Gas Operations 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, which struck the upper Texas coast in September 2008. 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

In May 2008, we 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, we 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 December 2008, we entered into an asset management agreement whereby we sold $110 million of our 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.

Interstate Pipeline Expansion

The Southeast Supply Header (SESH) pipeline project, a joint venture between CenterPoint Energy Gas Transmission, our wholly owned subsidiary, 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, CenterPoint Energy experienced substantial declines in the value of the assets of its pension plan, in which we participate, 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 CenterPoint Energy's pension plan assets that occurred during 2008 will result in increased charges to pension plan expense in 2009, which will adversely impact earnings, and may also result in the need for CenterPoint Energy to make significant cash contributions to its 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:

- 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 rate actions and increases, allowing recovery of costs, including those associated with Hurricane Ike, 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;

- the ability of Reliant Energy, Inc. (RRI) to satisfy its obligations to us 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 CenterPoint Energy's 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;
- acquisitions 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

Our results of operations are affected by seasonal fluctuations in the demand for natural gas and price movements of energy commodities as well as natural gas basis differentials. Our results of operations are also affected by, among other things, the actions of various federal and state governmental authorities having jurisdiction over rates we charge, competition in our various business operations, debt service costs and income tax expense.

The following table sets forth selected financial data (in millions) for the years ended December 31, 2006, 2007 and 2008, followed by a discussion of our consolidated results of operations based on operating income. We have provided a reconciliation of consolidated operating income to net income below.

	Year Ended December 31,		
	2006	2007	2008
Revenues	$ 7,528	$ 7,776	$ 9,395
Expenses:			
Natural gas	5,909	5,995	7,466
Operation and maintenance	798	800	828
Depreciation and amortization	200	215	218
Taxes other than income taxes	149	140	166
Total	7,056	7,150	8,678
Operating Income	472	626	717
Interest and other finance charges	(167)	(187)	(206)
Equity in earnings of unconsolidated affiliates	6	16	51
Other income, net	12	5	9
Income Before Income Taxes	323	460	571
Income Tax Expense	(116)	(173)	(228)
Net Income	$ 207	$ 287	$ 343

2008 Compared to 2007. We reported net income of $343 million for 2008 as compared to $287 million for 2007. The increase in net income of $56 million was primarily due to a $91 million increase in operating income from our business segments as discussed below and a $35 million increase in equity in earnings of unconsolidated affiliates related primarily to SESH, partially offset by a $55 million increase in income tax expense due to higher earnings and a $19 million increase in interest expense.

Our effective tax rate for 2008 and 2007 was 40.0% and 37.6%, respectively.

2007 Compared to 2006. We reported net income of $287 million for 2008 as compared to $207 million for 2007. The increase in net income of $80 million was primarily due to a $154 million increase in operating income from our business segments as discussed below, partially offset by a $57 million increase in income tax expense due to higher earnings and a $20 million increase in interest expense.

Our effective tax rate for 2007 and 2006 was 37.6% and 36.1%, respectively.

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
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	1	(3)	—
Total Consolidated Operating Income	$ 472	$ 626	$ 717

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.

Fluctuations in Commodity Prices and Derivative Instruments

For information regarding our exposure to risk as a result of fluctuations in commodity prices and derivative instruments, please read “Quantitative and Qualitative Disclosures About Market Risk” in Item 7A of this report.

LIQUIDITY

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, tax payments and working capital needs. Our principal anticipated cash requirements for 2009 include approximately $637 million of capital expenditures and maturing long-term debt aggregating approximately $7 million.

We expect that borrowings under our credit facilities, anticipated cash flows from operations and intercompany borrowings will be sufficient to meet our anticipated cash needs in 2009. Cash needs or discretionary financing or refinancing may result in the issuance of debt securities in the capital markets or the arrangement of additional credit facilities. Issuances of 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
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
Total	$ 533	$ 637	$ 530	$ 413	$ 406	$ 407

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
Long-term debt	$ 3,719	$ 7	$ 563	$ 1,722	$ 1,427
Interest payments — long-term debt(1)	1,693	209	394	275	815
Short-term borrowings	153	153	—	—	—
Operating leases(2)	74	14	22	13	25
Benefit obligations(3)	—	—	—	—	—
Purchase obligations(4)	24	24	—	—	—
Non-trading derivative liabilities	134	87	41	6	—
Other commodity commitments(5)	3,520	776	911	877	956
Income taxes(6)	—	—	—	—	—
Total contractual cash obligations	$ 9,317	$ 1,270	$ 1,931	$ 2,893	$ 3,223

(1) 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.

(2) For a discussion of operating leases, please read Note 9(b) to our consolidated financial statements.

(3) We expect to contribute approximately $9 million to our postretirement benefits plan in 2009 to fund a portion of our obligations in accordance with rate orders or to fund pay-as-you-go costs associated with the plan.

(4) 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.

(5) For a discussion of other commodity commitments, please read Note 9(a) to our consolidated financial statements.

(6) As of December 31, 2008, we had a receivable for uncertain tax positions of $12 million.

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

Prior to CenterPoint Energy's distribution of its ownership in RRI to its shareholders, we 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 us against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for our benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, we, CenterPoint Energy and RRI amended that agreement and we released the letters of credit we held as security. Under the revised agreement, RRI agreed to provide cash or new letters of credit to secure us against exposure under the remaining guaranties as calculated under the revised agreement if and to the extent changes in market conditions exposed us to a risk of loss on those guaranties.

Our potential exposure 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 CenterPoint Energy 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. In May 2008, we 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, we entered into an asset management agreement whereby we sold $110 million of our 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.

Credit and Receivables Facilities. Our $950 million credit facility's first drawn cost is the London Interbank Offered Rate (LIBOR) plus 45 basis points based on our current credit ratings. The facility contains covenants, including a debt to total capitalization covenant.

Under the 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 our credit rating. Borrowings under the facility are subject to customary terms and conditions. However, there is no requirement that we 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 the credit facility are subject to acceleration upon the occurrence of events of default that we consider customary.

In November 2008, we 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 are currently in compliance with the various business and financial covenants contained in the respective receivables and credit facilities.

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	CERC Corp.	Revolver	$ 950(1)	$ 781	June 29, 2012
November 25, 2008	CERC	Receivables	375	—	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 our facility.

Our $950 million credit facility backstops a $915 million commercial paper program under which we began issuing commercial paper in February 2008. Our commercial paper is rated "P-3" 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 "F2" by Fitch, Inc. (Fitch). As a result of the credit ratings on our commercial paper program, 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. At December 31, 2008, we had 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 participate in a money pool through which we and certain of our affiliates 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 CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper. At February 13, 2009, we had no borrowings from the money pool. The money pool may not provide sufficient funds to meet our cash needs.

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 our senior unsecured debt:

	Moody's		S&P		Fitch	
Company/Instrument	**Rating**	**Outlook(1)**	**Rating**	**Outlook(2)**	**Rating**	**Outlook(3)**
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 $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.

CenterPoint Energy Services, Inc. (CES), our wholly owned subsidiary 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 our credit ratings (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, we and our subsidiaries purchase natural gas under supply agreements that contain an aggregate credit threshold of $100 million based on our 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 our credit ratings decline below the applicable threshold levels, we 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 CenterPoint Energy's revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $50 million by us will cause a default. In addition, four outstanding series of CenterPoint Energy's senior notes, aggregating $950 million in principal amount as of February 13, 2009, provide that a payment default by us 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 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 and weather 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 indemnification obligations to us or in connection with the contractual arrangement pursuant to which we are 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;

- 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. Our bank facility and our receivables facility limit our debt as a percentage of our total capitalization to 65%.

Relationship with CenterPoint Energy. We are an indirect wholly owned subsidiary of CenterPoint Energy. As a result of this relationship, the financial condition and liquidity of our parent company could affect our access to capital, our credit standing and our financial condition.

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 of CenterPoint Energy.

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 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.

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 Statement of Financial Accounting Standards (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 2%. 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 was approximately $46 million.

Unbilled Energy Revenues

Revenues related to 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 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.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(n) to the consolidated financial statements, incorporated herein by reference, for a discussion of new accounting pronouncements that affect us.

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 2(o) to our consolidated financial statements, we participate in CenterPoint Energy’s qualified and non-qualified pension plans covering substantially all employees. The expected pension expense for 2009 is $47 million, of which we expect $41 million to impact pre-tax earnings, based on an expected return on plan assets of 8.00% and a discount rate of 6.90% as of December 31, 2008. We recorded pension income of $2 million for the year ended December 31, 2008. The increase in pension expense in 2009 is primarily the result of a decline in 2008 in plan assets of the CenterPoint Energy pension plan, in which we participate. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plans will impact our future pension expense. We cannot predict with certainty what these factors will be in the future.

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 and bank loans from affiliates that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $449 million and $1.0 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 $2 million annually.

At both December 31, 2007 and 2008, we had outstanding fixed-rate debt aggregating $2.8 billion in principal amount and having a fair value of $2.9 billion and $2.6 billion, respectively. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Note 7 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $104 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.

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 Stockholder of
CenterPoint Energy Resources Corp.
Houston, Texas

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp. and subsidiaries (the “Company”, an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2008 and 2007, and the related statements of consolidated income, comprehensive income, cash flows and stockholder’s equity 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of CenterPoint Energy Resources Corp. 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.

DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 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.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management's report in this annual report.

/s/ DAVID M. MCCLANAHAN

President and Chief Executive Officer

/s/ GARY L. WHITLOCK

Executive Vice President and Chief Financial Officer

March 11, 2009

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2006	2007	2008
		(In Millions)	
Revenues	$ 7,528	$ 7,776	$ 9,395
Expenses:			
Natural gas	5,909	5,995	7,466
Operation and maintenance	798	800	828
Depreciation and amortization	200	215	218
Taxes other than income taxes	149	140	166
Total	7,056	7,150	8,678
Operating Income	472	626	717
Other Income (Expense):			
Interest and other finance charges	(167)	(187)	(206)
Equity in earnings of unconsolidated affiliates	6	16	51
Other, net	12	5	9
Total	(149)	(166)	(146)
Income Before Income Taxes	323	460	571
Income tax expense	(116)	(173)	(228)
Net Income	$ 207	$ 287	$ 343

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2006	2007	2008
		(In Millions)	
Net income	$ 207	$ 287	$ 343
Other comprehensive income (loss), net of tax:			
Adjustment to pension and other postretirement plans (net of tax of $-0-, a tax benefit of $6, and net of tax of $3)	—	13	(13)
Net deferred gain from cash flow hedges (net of tax of $11, $6 and $-0-)	22	12	—
Reclassification of net deferred gain from cash flow hedges realized in net income (net of tax of $3, $20 and $3)	(7)	(33)	(5)
Other comprehensive income (loss)	15	(8)	(18)
Comprehensive income	$ 222	$ 279	$ 325

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2008
	(In Millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable, net	732	774
Accrued unbilled revenue	456	480
Accounts and notes receivable — affiliated companies	82	9
Inventory	430	495
Non-trading derivative assets	38	118
Deferred income tax assets	40	25
Prepaid expenses and other current assets	235	327
Total current assets	2,014	2,229
Property, Plant and Equipment, Net	5,031	5,363
Other Assets:		
Goodwill	1,696	1,696
Non-trading derivative assets	11	20
Investment in unconsolidated affiliates	88	345
Notes receivable from unconsolidated affiliates	148	323
Other	146	235
Total other assets	2,089	2,619
Total Assets	$ 9,134	$ 10,211
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ 232	$ 153
Current portion of long-term debt	307	7
Accounts payable	661	722
Accounts and notes payable — affiliated companies	144	33
Taxes accrued	118	99
Interest accrued	59	54
Customer deposits	59	59
Non-trading derivative liabilities	60	87
Other	186	302
Total current liabilities	1,826	1,516
Other Liabilities:		
Accumulated deferred income taxes, net	778	864
Non-trading derivative liabilities	14	47
Benefit obligations	116	114
Regulatory liabilities	474	508
Other	167	101
Total other liabilities	1,549	1,634
Long-Term Debt	2,645	3,712
Commitments and Contingencies (Note 9)		
Stockholder's Equity	3,114	3,349
Total Liabilities And Stockholder's Equity	$ 9,134	$ 10,211

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2006	2007	2008
		(In Millions)	
Cash Flows from Operating Activities:			
Net income	$ 207	$ 287	$ 343
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	200	215	218
Deferred income taxes	17	64	92
Amortization of deferred financing costs	8	8	9
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	248	14	(66)
Accounts receivable/payable, affiliates	(19)	(8)	41
Inventory	(78)	(105)	(95)
Accounts payable	(262)	(175)	60
Fuel cost recovery	111	(93)	45
Interest and taxes accrued	(4)	23	(24)
Net non-trading derivative assets and liabilities	(18)	13	(19)
Margin deposits, net	(156)	65	(182)
Other current assets	(80)	(27)	(8)
Other current liabilities	29	(16)	17
Other assets	6	(7)	(3)
Other liabilities	18	(12)	(14)
Other, net	(15)	(3)	(33)
Net cash provided by operating activities	273	241	360
Cash Flows from Investing Activities:			
Capital expenditures	(599)	(676)	(532)
Increase in notes receivable from unconsolidated affiliates	—	(148)	(175)
Investment in unconsolidated affiliates	(13)	(39)	(206)
Other, net	(9)	(10)	34
Net cash used in investing activities	(621)	(873)	(879)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	187	45	(79)
Long-term revolving credit facilities, net	—	150	776
Payments of long-term debt	(152)	(7)	(307)
Proceeds from long-term debt	324	650	300
Decrease in notes with affiliates, net	(103)	(107)	(79)
Contribution from parent	168	—	—
Dividends to parent	(100)	(100)	(100)
Debt issuance costs	(1)	(6)	(2)
Other, net	(1)	3	10
Net cash provided by financing activities	322	628	519
Net Decrease in Cash and Cash Equivalents	(26)	(4)	—
Cash and Cash Equivalents at Beginning of the Year	31	5	1
Cash and Cash Equivalents at End of the Year	$ 5	$ 1	$ 1
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 162	$ 167	$ 210
Income taxes (refunds)	(25)	106	145
Non-cash transactions:			
Accounts payable related to capital expenditures	$ 142	$ 51	$ 52

See Notes to the Company’s Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED STOCKHOLDER'S EQUITY

	2006		2007		2008	
	Shares	Amount	Shares	Amount	Shares	Amount
			(In millions, except share amounts)			
Common Stock						
Balance, beginning of year	1,000	$ —	1,000	$ —	1,000	$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		2,404		2,403		2,406
Contribution to parent		(3)		—		—
Other		2		3		10
Balance, end of year		2,403		2,406		2,416
Retained Earnings						
Balance, beginning of year		398		505		692
Net income		207		287		343
Dividend to parent		(100)		(100)		(100)
Balance, end of year		505		692		935
Accumulated Other Comprehensive Income						
Balance, end of year:						
Net deferred gain from cash flow hedges		26		5		—
Adjustment to pension and postretirement plans		(2)		11		(2)
Total accumulated other comprehensive income, end of year		24		16		(2)
Total Stockholder's Equity		$ 2,932		$ 3,114		$ 3,349

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Background

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

The Company is an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

For a description of the Company's reportable business segments, see Note 12.

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 CERC Corp. and its wholly owned and majority owned subsidiaries are included in the Company's 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 natural gas sales and services under the accrual method and these revenues are recognized upon delivery to customers. 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 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 includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2007	December 31, 2008
		(In millions)	
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	13	26	45
Total		5,837	6,313
Accumulated depreciation and amortization:			
Natural Gas Distribution		590	708
Competitive Natural Gas Sales and Services		9	11
Interstate Pipelines		160	182
Field Services		29	28
Other property		18	21
Total accumulated depreciation and amortization		806	950
Property, plant and equipment, net		$ 5,031	$ 5,363

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 $62 million and $46 million, respectively. The decrease in asset retirement obligations in 2008 of $16 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 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	2008
	(In millions)	
Regulatory assets in other long-term assets	$ 53	$ 53
Regulatory liabilities	(474)	(508)
Net	$ (421)	$ (455)

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 $445 million and $478 million, respectively, are classified as regulatory liabilities in the 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.

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

	Year Ended December 31,		
	2006	2007	2008
		(In millions)	
Depreciation expense	$ 181	$ 193	$ 200
Amortization expense	19	22	18
Total depreciation and amortization expense	$ 200	$ 215	$ 218

(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 $6 million, $12 million and $5 million, respectively.

(h) Income Taxes

The Company is included in the consolidated income tax returns of CenterPoint Energy. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. Pursuant to the tax sharing agreement with CenterPoint Energy, in 2006, the Company received allocations of CenterPoint Energy’s tax expense totaling $3 million.

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. A valuation allowance is established against deferred tax assets for which management believes realization is not considered more likely than not. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy.

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 8.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $37 million and $33 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 $37 million, $42 million and $53 million, respectively.

On November 25, 2008, the Company 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 million 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	2008
	(In millions)	
Materials and supplies	$ 35	$ 54
Natural gas	395	441
Total inventory	$ 430	$ 495

(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.

CenterPoint Energy has a Risk Oversight Committee composed of corporate and business segment officers that oversees all commodity price, weather and credit risk activities, including 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 CenterPoint Energy's board of directors, approve use of new products and commodities, monitor positions and ensure compliance with CenterPoint Energy's risk management policies and procedures and limits established by CenterPoint Energy's board of directors.

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) 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.

(m) 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.

(n) 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.

(o) Employee Benefit Plans

Pension Plans

Substantially all of the Company's employees participate in CenterPoint Energy's qualified non-contributory defined benefit pension plan. 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.

CenterPoint Energy's funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Pension expense is allocated to the Company based on covered employees. This calculation is intended to allocate pension costs in the same manner as a separate employer plan. Assets of the plan are not segregated or restricted by CenterPoint Energy's participating subsidiaries. The Company recognized pension expense of $16 million and $5 million for the years ended December 31, 2006 and 2007, respectively, and pension income of $3 million for the year ended December 31, 2008.

In addition to the plan, the Company participates in CenterPoint Energy's non-qualified benefit restoration plans, which allow participants to receive the benefits to which they would have been entitled under CenterPoint Energy's non-contributory pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. The expense associated with the non-qualified pension plan was less than $1 million for each of the years ended December 31, 2006 and 2007, respectively, and $1 million for the year ended December 31, 2008.

Savings Plan

The Company participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. 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. CenterPoint Energy allocates to the Company the savings plan benefit expense related to the Company's employees. Savings plan benefit expense was $17 million for each of the years ended December 31, 2006 and 2007 and $18 million for the year ended December 31, 2008.

Postretirement Benefits

The Company's employees participate in CenterPoint Energy's plans which provide 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 Company is required to fund a portion of its obligations in accordance with rate orders. All other obligations are funded on a pay-as-you-go basis.

The net postretirement benefit cost includes the following components:

	Year Ended December 31, 2006	2007	2008
		(In millions)	
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	7	7	7
Expected return on plan assets	(1)	(1)	(1)
Amortization of prior service cost	2	2	2
Other	1	—	—
Net postretirement benefit cost	$ 10	$ 9	$ 9

The Company used the following assumptions to determine net postretirement benefit costs:

	Year Ended December 31, 2006	2007	2008
Discount rate	5.70%	5.85%	6.40%
Expected return on plan assets	4.80%	4.50%	4.50%

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.

Following are reconciliations of the Company's beginning and ending balances of its postretirement benefit plan's benefit obligation, plan assets and funded status for 2007 and 2008. The measurement dates for plan assets and obligations were December 31, 2007 and 2008.

	Year Ended December 31, 2007	2008
	(In millions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 134	$ 119
Service cost	1	1
Interest cost	7	7
Benefits paid	(20)	(19)
Medicare reimbursement	3	1
Participant contributions	4	4
Actuarial loss	(10)	7
Accumulated benefit obligation, end of year	$ 119	$ 120
Change in Plan Assets		
Plan assets, beginning of year	$ 20	$ 20
Benefits paid	(20)	(19)
Employer contributions	15	14
Participant contributions	4	4
Medicare reimbursement received	—	1
Actual investment return	1	—
Plan assets, end of year	$ 20	$ 20
Amounts Recognized in Balance Sheets		
Current liabilities-other	(6)	(8)
Other liabilities-benefit obligations	$ (93)	$ (92)
Net liability, end of year	$ (99)	$ (100)
Actuarial Assumptions		
Discount rate	6.40%	6.90%
Expected long-term return on assets	4.50%	4.50%
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 (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

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 expected duration of obligations specific to the characteristics of CenterPoint Energy's plans.

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.

For measurement purposes, healthcare costs are assumed to increase 6.5% during 2009, after which this rate decreases until reaching the ultimate rate of 5.5% in 2011. Prescription drug costs are assumed to increase 12% in 2009, after which this rate decreases until reaching the ultimate rate of 5.5% in 2014.

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

	Year Ended December 31, 2007	2008
	(In millions)	
Unrecognized actuarial loss	$ 3	$ 14
Unrecognized prior service cost	12	10
	15	24
Less deferred tax benefit (1)	(26)	(21)
Net amount recognized in accumulated other comprehensive (income) loss	$ (11)	$ 3

(1) The Company's postretirement benefit obligation is reduced by the impact of non-taxable government subsidies under the Medicare Prescription Drug Act. Because the subsidies are non-taxable, the temporary difference used in measuring the deferred tax impact is determined on the unrecognized losses excluding such subsidies. Accordingly, the unrecognized losses used for determining deferred taxes were $64 million and $54 million as of December 31, 2007 and 2008, respectively.

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

	Postretirement Benefits
	(In millions)
Net gain	$ 11
Amortization of prior service cost	(2)
Total recognized in other comprehensive income	$ 9

The total expense recognized in net periodic costs and other comprehensive income was $18 million for postretirement benefits 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:

	Postretirement Benefits
	(In millions)
Unrecognized prior service cost	$ 2
Amounts in other comprehensive income to be recognized as net periodic cost in 2009	$ 2

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	$ 5	$ (4)
Effect on the total of service and interest cost	—	—

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

	December 31,	
	2007	2008
Domestic equity securities	6%	4%
Debt securities	93	96
Cash	1	—
Total	100%	100%

In managing the investments associated with the postretirement benefit plan, 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 asset allocation ranges for its postretirement benefit plan:

Domestic equity securities	0-10%
Debt securities	90-100%
Cash	0-2%

The Company expects to contribute $9 million to its postretirement benefits plan in 2009. The following benefit payments are expected to be paid by the postretirement benefit plan:

	Postretirement Benefit Plan	
	Benefit Payments	Medicare Subsidy Receipts
	(in millions)	
2009	$ 12	$ (2)
2010	13	(2)
2011	13	(2)
2012	14	(2)
2013	14	(3)
2014-2018	73	(17)

Postemployment Benefits

The Company participates in CenterPoint Energy's plan that provides postemployment benefits for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). The Company recorded a postemployment benefit cost of $3 million, income of $2 million and cost of $1 million for the years ended December 31, 2006, 2007 and 2008, respectively. Amounts relating to postemployment benefits included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2007 and 2008, were $17 million and $16 million, respectively.

Other Non-Qualified Plans

The Company participates in CenterPoint Energy's 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 benefit expense relating to these programs was less than $1 million each year. Amounts relating to deferred compensation plans included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2007 and 2008, were $4 million and $1 million, respectively.

(p) Other Current Assets and Liabilities

Included in other current assets on the Consolidated Balance Sheets at December 31, 2007 and 2008 was $47 million and $42 million, respectively, of margin deposits and $53 million and $128 million, respectively of under recovered gas cost. Included in other current liabilities on the Consolidated Balance Sheets at December 31, 2007 and 2008 was $30 million and $79 million, respectively, of over recovered gas cost.

3. Regulatory Matters

(a) Hurricane Ike

The Company's natural gas distribution business (Gas Operations) 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, which struck the upper Texas coast in September 2008. 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) 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 filed second motions for rehearing on this order. On February 26, 2009, the Railroad Commission denied the second motions on rehearing reaffirming its original decision. In December 2008, Gas Operations implemented the approved rates for the nine TCUC cities and the environs. Cities with settled rates have the opportunity to adopt the rates established by the Railroad Commission or retain the rates agreed in their settlements.

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. Related Party Transactions

The Company participates in a "money pool" through which it 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 CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper. The Company had money pool borrowings of $67 million and $-0- at December 31, 2007 and 2008, respectively, which are included in accounts and notes payable—affiliated companies in the Consolidated Balance Sheets.

For the years ended December 31, 2006, 2007 and 2008, the Company had net interest expense related to affiliate borrowings of $2 million, $3 million and less than $1 million, respectively.

CenterPoint Energy provides some corporate services to the Company. The costs of services have been charged directly to the Company using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. These charges are not necessarily indicative of what would have been incurred had the Company not been an affiliate. Amounts charged to the Company for these services were $133 million, $133 million and $140 million for 2006, 2007 and 2008, respectively, and are included primarily in operation and maintenance expenses.

Pursuant to the tax sharing agreement with CenterPoint Energy, the Company received allocations of CenterPoint Energy's tax expense of $3 million for 2006 which was recorded in additional paid-in capital.

In each of 2006, 2007 and 2008, the Company paid dividends of $100 million to its parent.

5. 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.

(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.

6. 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	$ 1	$ —	$ —	$ —	$ 1
Investments, including money market funds	11	—	—	—	11
Derivative assets	8	155	49	(74)	138
Total assets	$ 20	$ 155	$ 49	$ (74)	$ 150
Liabilities					
Derivative liabilities	44	244	107	(261)	134
Total liabilities	$ 44	$ 244	$ 107	$ (261)	$ 134

(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

7. 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:				
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(2)	150	—	926	—
Unamortized discount and premium(3)	(2)	—	(5)	—
Total long-term debt	2,645	307	3,712	7
Total debt	$ 2,645	$ 539	$ 3,712	$ 160

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

(2) Classified as long-term debt because the termination date of the facility under which the funds were borrowed is more than one year beyond the dates referenced in the table.

(3) 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, the Company 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 million 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, the Company 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.

(b) Long-term Debt

Senior Notes. In May 2008, the Company 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.

Revolving Credit Facility. The Company's $950 million revolving credit facility's first drawn cost is the London Interbank Offered Rate (LIBOR) plus 45 basis points based on the Company's current credit ratings. The facility contains covenants, including a debt to total capitalization covenant of 65%. Under the 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 Company's credit rating.

As of December 31, 2008, the Company had $926 million of borrowings and no letters of credit under its $950 million credit facility. The Company had no commercial paper outstanding at December 31, 2008. The Company was in compliance with all debt covenants as of December 31, 2008.

Maturities. The Company's consolidated maturities of long-term debt and sinking fund requirements are $7 million in 2009, $7 million in 2010, $556 million in 2011, $957 million in 2012 and $765 million in 2013.

8. 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	$ 97	$ 81	$ 118
State	36	28	18
Total current	133	109	136
Deferred:			
Federal	(22)	58	60
State	5	6	32
Total deferred	(17)	64	92
Income tax expense	$ 116	$ 173	$ 228

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	$ 323	$ 460	$ 571
Federal statutory rate	35%	35%	35%
Income taxes at statutory rate	113	161	200
Net addition (reduction) in taxes resulting from:			
State income taxes, net of valuation allowance and federal income tax	27	22	32
Decrease in settled and uncertain income tax positions	(20)	(8)	(1)
Other, net	(4)	(2)	(3)
Total	3	12	28
Income tax expense	$ 116	$ 173	$ 228
Effective income tax rate	36.1%	37.6%	40.0%

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

	December 31, 2007	December 31, 2008
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 16	$ 13
Deferred gas costs	26	12
Total current deferred tax assets	42	25
Non-current:		
Employee benefits	87	80
Loss and credit carryforwards	24	8
Regulatory liabilities, net	—	11
Other	24	11
Total non-current deferred tax assets before valuation allowance	135	110
Valuation allowance	(18)	(5)
Total non-current deferred tax assets	117	105
Total deferred tax assets, net	159	130
Deferred tax liabilities:		
Current:		
Non-trading derivative liabilities, net	$ 2	$ —
Non-current:		
Depreciation	851	927
Regulatory assets, net	16	—
Other	28	42
Total non-current deferred tax liabilities	895	969
Total deferred tax liabilities	897	969
Accumulated deferred income taxes, net	$ 738	$ 839

The Company is included in the consolidated income tax returns of CenterPoint Energy. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy.

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2008, the Company has approximately $128 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 $3 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 full valuation allowance was established in prior periods. A re-measurement of the deferred tax asset arising from the state capital loss carryforward caused a decrease equal to $12 million in both the deferred tax asset and the associated valuation allowance. The change did not impact the effective income tax rate.

Uncertain Income Tax Positions. The Company adopted the provisions of FIN 48 on January 1, 2007. The cumulative effect of adopting FIN 48 as of January 1, 2007 was a credit to retained earnings of less than $1 million. A reconciliation of the change in unrecognized tax benefits for 2007 and 2008 is as follows:

	December 31, 2007	December 31, 2008
	(In millions)	
Balance, beginning of year	$ 1	$ (11)
Tax Positions related to prior years:		
Reductions	(10)	(1)
Settlements	(2)	—
Balance, end of year	$ (11)	$ (12)

The Company has approximately $1 million of unrecognized tax benefits that, if recognized, would reduce the effective income tax rate for both 2007 and 2008. The Company recognizes interest and penalties as a component of income tax expense. The Company recognized approximately $3 million and $1 million of benefit for interest on uncertain income tax positions during 2007 and 2008, respectively. The Company accrued $3 million and $4 million of interest receivable 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. CenterPoint Energy's consolidated federal income tax returns have been audited and settled through the 2003 tax year and the Internal Revenue Service (IRS) is currently at various stages of the examination process for tax years 2004 through 2007. 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.

CenterPoint Energy reached a tentative settlement with the IRS for a number of tax issues in the fourth quarter of 2006, resulting in a reduction in the Company's income tax expense for 2006 of approximately $20 million.

9. 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, including major work equipment (in millions):

2009	$ 14
2010	11
2011	11
2012	7
2013	6
2014 and beyond	25
Total	$ 74

Total rental expense for all operating leases was $51 million, $43 million and $41 million in 2006, 2007 and 2008, respectively.

(c) Capital Commitments

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 Federal Energy Regulatory Commission (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 Matters

Legal Matters

RRI Indemnified Litigation

CenterPoint Energy or its predecessor, Reliant Energy, Incorporated (Reliant Energy), and certain of their present or former subsidiaries are named as defendants in several lawsuits described below. Under a master separation agreement between CenterPoint Energy and Reliant Energy, Inc. (formerly Reliant Resources, Inc.) (RRI), CenterPoint Energy and its subsidiaries, including the Company, 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." Pursuant to the indemnification obligation, RRI is defending CenterPoint Energy and its subsidiaries to the extent named in these lawsuits. Although the ultimate outcome of these matters cannot be predicted at this time, CenterPoint Energy 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. CenterPoint Energy's former affiliate, RRI, was a participant in gas trading in the California and Western markets. These lawsuits, many of which have been filed as class actions, allege violations of state and federal antitrust laws. Plaintiffs in these lawsuits are seeking a variety of forms of relief, including, among others, recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages, full consideration damages and attorneys' fees. CenterPoint Energy and/or Reliant Energy were named in approximately 30 of these lawsuits, which were instituted between 2003 and 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 CenterPoint Energy was not a successor to the liabilities of a subsidiary of RRI, and CenterPoint Energy 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 CenterPoint Energy from those cases. In August 2008, the plaintiffs in five additional cases also agreed to dismiss CenterPoint Energy 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, CenterPoint Energy 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. CenterPoint Energy believes it is not a proper defendant in the remaining cases and will continue to pursue dismissal from those cases.

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. The Company believes that there has been no systematic mismeasurement of gas and that the lawsuits are without merit. The Company does not expect the ultimate outcome of the lawsuits to have a material impact on its financial condition, results of operations or cash flows.

Gas Cost Recovery Litigation. In October 2002, a lawsuit was filed on behalf of certain ratepayers of the Company in state district court in Wharton County, Texas against the Company, CenterPoint Energy, 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 the Company, 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 ratepayers of the Company in Texas and Arkansas in circuit court in Miller County, Arkansas against CERC Corp., CenterPoint Energy, EGMC, 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, CERC Corp., CenterPoint Energy, 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 CERC Corp., CenterPoint Energy, 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 the Company. 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 the Company 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 the Company seeking to recover alleged overcharges for gas or gas services allegedly provided by the Company 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, the Company's gas purchases were reviewed back to 1971. The review concluded that the Company's gas costs were "reasonable and prudent," but the Company 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 the Company. 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 an entity of the Company 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 does not expect the outcome of this matter to have a material impact on its financial condition, results of operations or cash flows.

Environmental Matters

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

At December 31, 2008, the Company 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. The Company 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, the Company 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 the Company or may have been owned by one of its former affiliates. The Company 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 the Company or its divisions. The Company 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 the Company, 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, the Company 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 formerly owned by the Company's predecessors have contained asbestos insulation and other asbestos-containing materials. The Company or its predecessor companies have been named, along with numerous others, as a defendant in lawsuits filed by certain individuals who claim injury due to exposure to asbestos during work at such formerly owned facilities. The Company anticipates that additional claims like those received may be asserted in the future. 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 the Company, 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 the Company held an interest in two oil and gas leases on a portion of the property at issue, neither it nor any other entities of the Company drilled or conducted other oil and gas operations on those leases. In January 2009, the Company 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 does not expect the outcome of this litigation to have a material adverse impact on its financial condition, results of operations or cash flows.

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 CenterPoint Energy's distribution of its ownership in RRI to its shareholders, the Company 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 the Company against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the Company's benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, the Company, CenterPoint Energy and RRI amended that agreement and the Company 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 the Company against exposure under the remaining guaranties as calculated under the revised agreement if and to the extent changes in market conditions exposed the Company to a risk of loss on those guaranties.

The potential exposure to the Company 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 CenterPoint Energy 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.

10. Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents 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 Note 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	$ 2,952	$ 3,079	$ 3,719	$ 3,568

11. 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)			
Revenues	$ 2,697	$ 1,566	$ 1,351	$ 2,162
Operating income	250	83	91	202
Net income	131	30	28	98

	Year Ended December 31, 2008			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions)			
Revenues	$ 2,952	$ 2,157	$ 1,960	$ 2,326
Operating income	242	130	129	216
Net income	126	60	67	90

12. Reportable Business Segments

Because the Company is an indirect wholly owned subsidiary of CenterPoint Energy, the Company's determination of reportable business segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting policies except that some executive benefit costs have not been allocated to business segments. 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: Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. 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. Our Other Operations business segment includes unallocated corporate costs and inter-segment eliminations.

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	Inter-segment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2006:						
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 (1)	255	133	37	181	2,738	437
Field Services (2)	119	31	10	89	608	65
Other	—	5	—	1	1,086	—
Reconciling Eliminations	—	(259)	—	—	(1,581)	—
Consolidated	$ 7,528	$ —	$ 200	$ 472	$ 8,815	$ 707
As of and for the year ended December 31, 2007:						
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 (1)	357	143	44	237	3,007	308
Field Services (2)	136	39	11	99	669	74
Other	—	—	—	(3)	670	—
Reconciling Eliminations	—	(237)	—	—	(765)	—
Consolidated	$ 7,776	$ —	$ 215	$ 626	$ 9,134	$ 580
As of and for the year ended December 31, 2008:						
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 (1)	477	173	46	293	3,578	189
Field Services (2)	213	39	12	147	826	122
Other	—	—	—	—	724	—
Reconciling Eliminations	—	(261)	—	—	(1,193)	—
Consolidated	$ 9,395	$ —	$ 218	$ 717	$ 10,211	$ 533

(1) 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.

(2) 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.

Revenues by Products and Services:	Year Ended December 31, 2006	2007	2008
		(In millions)	
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	101	107	128
Total	$ 7,528	$ 7,776	$ 9,395

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

None.

Item 9A(T). ***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.

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

None.

PART III

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

The information called for by Item 10 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

Item 11. ***Executive Compensation***

The information called for by Item 11 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

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

The information called for by Item 12 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

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

The information called for by Item 13 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

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

Aggregate fees billed to the Company during the fiscal years ending December 31, 2007 and 2008 by its principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31, 2007	Year Ended December 31, 2008
Audit fees (1)	$ 1,205,900	$ 1,199,800
Audit-related fees (2)	93,720	86,869
Total audit and audit-related fees	1,299,620	1,286,669
Tax fees	—	—
All other fees	—	—
Total fees	$ 1,299,620	$ 1,286,669

(1) For 2008 and 2007, amounts include fees for services provided by the principal accounting firm relating to the integrated audit of financial statements and internal control over financial reporting, statutory audits, attest services, and regulatory filings.

(2) For 2008 and 2007, includes fees for consultations concerning financial accounting and reporting standards and various agreed-upon or expanded procedures related to accounting records to comply with financial accounting or regulatory reporting matters.

The Company is not required to have, and does not have, an audit committee.

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:

I, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 71.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholder of
CenterPoint Energy Resources Corp.
Houston, Texas

We have audited the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries (the “Company”, an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and have issued our report thereon dated March 11, 2009; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company listed in the index at Item 15(a)(2). This consolidated financial statement schedule is 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 schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 2009

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

(An Indirect Wholly Owned Subsidiary of 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 (1)	Deductions From Reserves(2)	Balance at End of Period
			(In millions)		
Year Ended December 31, 2008:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 37	$ 53	$ 3	$ 60	$ 33
Deferred tax asset valuation allowance	18	(1)	(12)	—	5
Year Ended December 31, 2007:					
Accumulated provisions:					
Uncollectible accounts receivable	32	42	—	37	37
Deferred tax asset valuation allowance	22	(4)	—	—	18
Year Ended December 31, 2006:					
Accumulated provisions:					
Uncollectible accounts receivable	38	37	—	43	32
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 11th day of March, 2009.

CENTERPOINT ENERGY RESOURCES CORP.
(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 March 11, 2009.

Signature	Title
/s/ DAVID M. MCCLANAHAN (David M. McClanahan)	Chairman, President and Chief Executive Officer (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)

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2008

INDEX OF EXHIBITS

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2(a)(1)	Agreement and Plan of Merger among the Company, Houston Lighting and Power Company ("HL&P"), HI Merger, Inc. and NorAm Energy Corp. ("NorAm") dated August 11, 1996	Houston Industries' ("HI's") Form 8-K dated August 11, 1996	1-7629	2
2(a)(2)	Amendment to Agreement and Plan of Merger among the Company, HL&P, HI Merger, Inc. and NorAm dated August 11, 1996	Registration Statement on Form S-4	333-11329	2(c)
2(b)	Agreement and Plan of Merger dated December 29, 2000 merging Reliant Resources Merger Sub, Inc. with and into Reliant Energy Services, Inc.	Registration Statement on Form S-3	333-54526	2
3(a)(1)	Certificate of Incorporation of Reliant Energy Resources Corp. ("RERC Corp.")	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(1)
3(a)(2)	Certificate of Merger merging former NorAm Energy Corp. with and into HI Merger, Inc. dated August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(2)
3(a)(3)	Certificate of Amendment changing the name to Reliant Energy Resources Corp.	Form 10-K for the year ended December 31, 1998	1-3187	3(a)(3)
3(a)(4)	Certificate of Amendment changing the name to CenterPoint Energy Resources Corp.	Form 10-Q for the quarter ended June 30, 2003	1-13265	3(a)(4)
3(b)	Bylaws of RERC Corp.	Form 10-K for the year ended December 31, 1997	1-3187	3(b)
4(a)(1)	Indenture, dated as of March 31, 1987, between NorAm and Chase Manhattan Bank, N.A., as Trustee, authorizing 6% Convertible Subordinated Debentures due 2012	NorAm's Registration Statement on Form S-3	33-14586	4.20
4(a)(2)	Supplemental Indenture to Exhibit 4(a)(1) dated as of August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	4(b)(2)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(b)(1)	Indenture, dated as of February 1, 1998, between RERC Corp. and Chase Bank of Texas, National Association, as Trustee	Form 8-K dated February 5, 1998	1-13265	4.1
4(b)(2)	Supplemental Indenture No. 1, dated as of February 1, 1998, providing for the issuance of RERC Corp.'s 6 1/2% Debentures due February 1, 2008	Form 8-K dated February 5, 1998	1-13265	4.2
4(b)(3)	Supplemental Indenture No. 2, dated as of November 1, 1998, providing for the issuance of RERC Corp.'s 6 3/8% Term Enhanced ReMarketable Securities	Form 8-K dated November 9, 1998	1-13265	4.1
4(b)(4)	Supplemental Indenture No. 3, dated as of July 1, 2000, providing for the issuance of RERC Corp.'s 8.125% Notes due 2005	Registration Statement on Form S-4	333-49162	4.2
4(b)(5)	Supplemental Indenture No. 4, dated as of February 15, 2001, providing for the issuance of RERC Corp.'s 7.75% Notes due 2011	Form 8-K dated February 21, 2001	1-13265	4.1
4(b)(6)	Supplemental Indenture No. 5, dated as of March 25, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated March 18, 2003	1-13265	4.1
4(b)(7)	Supplemental Indenture No. 6, dated as of April 14, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated April 7, 2003	1-13265	4.2
4(b)(8)	Supplemental Indenture No. 7, dated as of November 3, 2003, providing for the issuance of CERC Corp.'s 5.95% Senior Notes due 2014	Form 8-K dated October 29, 2003	1-13265	4.2
4(b)(9)	Supplemental Indenture No. 8, dated as of December 28, 2005, providing for the issuance of CERC Corp.'s 6 1/2% Debentures due 2008	CenterPoint Energy, Inc.'s ("CNP's") Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(b)(10)	Supplemental Indenture No. 9, dated as of May 18, 2006, providing for the issuance of CERC Corp.'s 6.15% Senior Notes due 2016	CNP's Form 10-Q for the quarter ended June 30, 2006	1-31447	4.7
4(b)(11)	Supplemental Indenture No. 10, dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CNP's Form 10-K for the year ended December 31, 2007	1-31447	4(f)(11)
4(b)(12)	Supplemental Indenture No. 11 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.125% Senior Notes due 2017	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.8

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(b)(13)	Supplemental Indenture No. 12 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.9
4(b)(14)	Supplemental Indenture No. 13 dated as of May 15, 2008, providing for the issuance of CERC Corp.'s 6.00% Senior Notes due 2018	CNP's Form 10-Q for quarter ended June 30, 2008	1-31447	4.9
4(c)	$950,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CERC Corp., as Borrower, and the banks named therein	CNP's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.5

There have not been filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities do not exceed 10% of the total assets of CERC. CERC hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10(a)	Service Agreement by and between Mississippi River Transmission Corporation and Laclede Gas Company dated August 22, 1989	NorAm's Form 10-K for the year ended December 31, 1989	1-13265	10.20
+12	Computation of Ratios of Earnings to Fixed Charges			
+23	Consent of Deloitte & Touche LLP			
+31.1	Rule 13a-14(a)/15d-14(a) Certification of David M. McClanahan			
+31.2	Rule 13a-14(a)/15d-14(a) Certification of Gary L. Whitlock			
+32.1	Section 1350 Certification of David M. McClanahan			
+32.2	Section 1350 Certification of Gary L. Whitlock			

Exhibit 12

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(millions of dollars)

	Year Ended December 31,				
	2004	2005	2006	2007 (1)	2008 (1)
Net Income	$ 144	$ 193	$ 207	$ 287	$ 343
Income taxes	87	116	116	173	228
Capitalized interest	(2)	(1)	(6)	(12)	(14)
	229	308	317	448	557
Fixed charges, as defined:					
Interest expense	178	176	167	187	213
Capitalized interest	2	1	6	12	14
Interest component of rentals charged to operating expense	10	11	17	14	13
Total fixed charges	190	188	190	213	240
Earnings, as defined	$ 419	$ 496	$ 507	$ 661	$ 797
Ratio of earnings to fixed charges	2.20	2.64	2.67	3.10	3.32

(1) Excluded from the computation of fixed charges for the years ended December 31, 2007 and 2008 is interest income of $2 million and $1 million, respectively, which is included in income tax expense.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-153052 on Form S-3 of our reports dated March 11, 2009, relating to the consolidated financial statements and consolidated financial statement schedule of CenterPoint Energy Resources Corp. and subsidiaries appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2008.

DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 2009

Exhibit 31.1

CERTIFICATIONS

I, David M. McClanahan, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 11, 2009

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

Exhibit 31.2

CERTIFICATIONS

I, Gary L. Whitlock, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 11, 2009

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

Exhibit 32.1

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

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2008 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, David M. McClanahan, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ David M. McClanahan
David M. McClanahan
President and Chief Executive Officer
March 11, 2009

Exhibit 32.2

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

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2008 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Gary L. Whitlock, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ Gary L. Whitlock

Gary L. Whitlock
Executive Vice President and Chief Financial Officer
March 11, 2009