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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2006

Or

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

For the transition period from __________ to __________

Commission File Number 1-13265

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

Delaware *(State or other jurisdiction of incorporation or organization)*	**76-0511406** *(I.R.S. Employer Identification Number)*
1111 Louisiana **Houston, Texas 77002** *(Address and zip code of principal executive offices)*	**(713) 207-1111** *(Registrant's telephone number, including area code)*

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

Title of Each Class	Name of Each Exchange On Which Registered
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 o No ☑

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o   Accelerated filer o   Non-accelerated filer ☑

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

The aggregate market value of the common equity held by non-affiliates as of June 30, 2006: None

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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 a 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 2004, 2005 and 2006.

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

General

We own and operate natural gas distribution systems in six states. Wholly owned subsidiaries of ours own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. Another 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 2006, approximately 40% of Gas Operations’ total throughput was attributable to residential customers and approximately 60% was attributable 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 2006, approximately 68% of the total throughput of Gas Operations’ business occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during those periods.

Supply and Transportation. In 2006, 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 2006 included BP Canada Energy Marketing Corp. (23.3% of supply volumes), HPL Marketing (14.6%), Kinder Morgan (11.4%), Tenaska Marketing Ventures (5.1%) and ConocoPhillips Company (4.7%). Numerous other suppliers provided the remaining 40.9% 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 sixteen years. Gas Operations anticipates that these gas supply and transportation contracts will be renewed prior to their expiration.

We actively engage in commodity price stabilization pursuant to annual gas supply plans filed with each of our state regulatory authorities. These price stabilization activities include 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 storage facility with a capacity of 7.0 billion cubic feet (Bcf). It has a working capacity of 2.1 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 capacity of 192 MMcf per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf gas equivalent). It owns liquefied natural gas plant facilities with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf gas equivalent) and a send-out capability 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, 2006, Gas Operations owned approximately 66,000 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 two subsidiaries, CenterPoint Energy Intrastate Pipeline, Inc. (CEIP) and CenterPoint Energy Services, Inc. (CES).

In 2006, CES marketed approximately 555 Bcf of natural gas, transportation and related energy services to nearly 7,000 customers (including approximately 36 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 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 ten states.

Intrastate Pipeline Operations. CEIP provides bundled and unbundled merchant and transportation services to shippers and end-users.

CES currently transports natural gas on over 30 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 2006, CES' VaR averaged $1.6 million with a high of $2.7 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 231 miles of intrastate pipeline in Louisiana and Texas and holds storage facilities in Texas under long-term leases.

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

Beginning in the fourth quarter of 2006, we are reporting our interstate pipelines and field services businesses as two separate business segments. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. Our pipelines business operates:

- two interstate natural gas pipelines; and
- 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 2006, approximately 26% of CEGT and MRT's total operating revenue was attributable to services provided to Gas Operations and approximately 11% 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. Since October 31, 2006, MRT's contract with Laclede has been terminable upon one year's prior notice. MRT has not received a termination notice and is currently negotiating a long-term contract with Laclede. Agreements for firm transportation, "no notice" transportation service and storage service in certain of Gas Operations' service areas (Arkansas, Louisiana and Oklahoma) expire in 2012.

Carthage to Perryville. In October 2005, CEGT signed a 10-year firm transportation agreement with XTO Energy (XTO) to transport 600 MMcf per day of natural gas from Carthage, Texas to CEGT's Perryville hub in Northeast Louisiana. To accommodate this transaction, CEGT filed a certificate application with the FERC in March 2006 to build a 172-mile, 42-inch diameter pipeline and related compression facilities. The capacity of the pipeline under this filing will be 1.25 Bcf per day. CEGT has signed firm contracts for the full capacity of the pipeline.

In October 2006, the FERC issued CEGT's certificate to construct, own and operate the pipeline and compression facilities. CEGT has begun construction of the facilities and expects to place the facilities in service in the second quarter of 2007 at a cost of approximately $500 million.

Based on interest expressed during an open season held in 2006, and subject to FERC approval, CEGT may expand capacity of the pipeline to 1.5 Bcf per day, which would bring the total estimated capital cost of the project to approximately $550 million. In September 2006, CEGT filed for approval to increase the maximum allowable operating pressure with the U.S. Department of Transportation (DOT). In December 2006, CEGT filed for the necessary certificate to expand capacity of the pipeline with the FERC. CEGT expects to receive the approvals in the third quarter of 2007.

During the four-year period subsequent to the in-service date of the pipeline, XTO can request, and subject to mutual negotiations that meet specific financial parameters and to FERC approval, CEGT would construct a 67-mile extension from CEGT's Perryville hub to an interconnect with Texas Eastern Gas Transmission at Union Church, Mississippi.

Southeast Supply Header. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., a wholly owned subsidiary, and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture (Southeast Supply Header or SESH) to construct, own and operate a 270-mile pipeline that will extend from CEGT's Perryville hub in northeast Louisiana to Gulfstream Natural Gas System, which is 50 percent owned by an affiliate of Spectra. In August 2006, the joint venture signed an agreement with Florida Power & Light Company (FPL) for firm transportation services, which subscribed approximately half of the planned 1 Bcf per day capacity of the pipeline. FPL's commitment was contingent on the approval of the FPL contract by the Florida Public Service Commission, which was received in December 2006. Subject to the joint venture receiving a certificate from the FERC to construct, own and operate the pipeline, subsidiaries of Spectra and us have committed to build the pipeline. In December 2006, the joint venture signed agreements with affiliates of Progress Energy Florida, Southern Company, Tampa Electric Company, and EOG Resources, Inc. bringing the total subscribed capacity to 945 MMcf per day. Additionally, SESH and Southern Natural Gas (SNG) have executed a definitive agreement that provides for SNG to jointly own the first 115 miles of the pipeline. Under the agreement, SNG will own an undivided interest in the portion of the pipeline from Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter will be increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that could increase the capacity up to 500 MMcf per day. An application to construct, own and operate the pipeline was filed with the FERC in December 2006. Subject to receipt of FERC authorization and construction in accordance with planned schedule, we currently expect an in service date in the summer of 2008. The total cost of the combined project is estimated to be $800 to $900 million with SESH's net costs of $700 to $800 million after SNG's contribution.

Proposed Mid-continent Crossing. In June 2006, CEGT and Spectra signed a memorandum of understanding to explore the potential development of a new natural gas pipeline to bring gas from areas in the Mid-continent region to pipelines serving the Northeast and Southeast markets (MCX). In January 2007, CEGT and Spectra announced that market and economic conditions did not support the construction of the proposed pipeline. CEGT and Spectra may continue to independently evaluate opportunities for building infrastructure to transport mid-continent natural gas, including projects in the vicinity of the proposed MCX.

Assets

Our interstate pipelines business currently owns and operates approximately 7,900 miles of natural gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. It also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.2 Bcf per day and a combined working gas capacity of approximately 59.0 Bcf. It also owns a 10% interest in the Bistineau storage facility located in Bienville Parish, Louisiana, with the remaining interest owned and operated by Gulf South Pipeline Company, LP. This facility has a total working gas capacity of 85.7 Bcf and approximately 1.1 Bcf per day of deliverability. 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 available to our customers, 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

Beginning in the fourth quarter of 2006, we are reporting our interstate pipelines and field services businesses as two separate business segments. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. 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, either directly or through its 50% interest in the Waskom 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. The ServiceStar operating division currently provides monitoring activities at 11,080 locations across Alabama, Arkansas, Colorado, Illinois, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, Texas and Wyoming.

Our field services 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.

Assets

Our field services business owns and operates approximately 3,700 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 available to our customers, 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 for our gathering operations is impacted by commodity pricing levels because of their influence on the level of drilling activity.

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 11 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 civil penalties for statutory violations and violations of the FERC's rules or orders and also expanded criminal penalties for such violations.

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.

Prior to repeal of the Public Utility Holding Company Act of 1935, as amended (1935 Act), effective February 8, 2006, CenterPoint Energy was a registered public utility holding company under the 1935 Act, and CenterPoint Energy and its subsidiaries were subject to a comprehensive regulatory scheme imposed by the SEC under that Act. Although the SEC did not regulate rates and charges under the 1935 Act, it did regulate the structure, financing, lines of business and internal transactions of public utility holding companies and their system companies.

The Energy Act repealed the 1935 Act , and since that date, CenterPoint Energy and its subsidiaries have no longer been subject to restrictions imposed under the 1935 Act. The Energy Act includes PUHCA 2005 which grants to the FERC 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 a new Public Utility Holding Company Act of 2005 (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 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 traditional cost-of-service regulation at rates regulated 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.

Arkansas. In January 2007, Gas Operations filed an application with the Arkansas Public Service Commission (APSC) to change its natural gas distribution rates. This filing seeks approval to change the base rate portion of a customer's natural gas bill, which makes up about 30 percent of the total bill and covers the cost of distributing natural gas. The filing does not apply to the Gas Supply Rate (GSR), which makes up the remaining approximately 70 percent of the bill. Through the GSR, Gas Operations passes through to its customers the actual cost it pays for the natural gas it purchases for use by its customers without any mark-up. In a separate filing in January 2007, Gas Operations reduced the GSR by about 9 percent. The APSC approved this GSR filing in January 2007.

The filing seeks approval by the APSC of new rates that would go into effect later this year and would generate approximately $51 million in additional revenue on an annual basis. The effect on individual monthly bills would vary depending on natural gas use and customer class. As part of the base rate filing, we are also proposing a mechanism that, if approved, would help stabilize revenues, eliminate the potential conflict between our efforts to earn a reasonable return on invested capital while promoting energy efficiency initiatives, and minimize the need for future rate cases. As part of the revenue stabilization mechanism, we proposed to reduce the requested return on equity by 35 basis points which would reduce the base rate increase by $1 million. The mechanism would be in place through December 31, 2010.

In Arkansas, the APSC in December 2006 adopted rules governing affiliate transactions involving public utilities operating in Arkansas. The rules treat as affiliate transactions all transactions between our Arkansas utility operations and our other divisions, as well as transactions between the Arkansas utility operations and our affiliates. All such affiliate transactions are required to be priced under an asymmetrical pricing formula under which the Arkansas utility operations would benefit from any difference between the cost of providing goods and services to or from the Arkansas utility operations and the market value of those goods or services. Additionally, the Arkansas utility operations are not permitted to participate in any financing other than to finance retail utility operations in Arkansas, which would preclude continuation of existing financing arrangements in which we finance our divisions and subsidiaries, including our Arkansas utility operations.

Although the Arkansas rules are now in effect, we and other gas and electric utilities operating in Arkansas sought reconsideration of the rules by the APSC. In February 2007, the APSC granted that reconsideration and suspended operation of the rules in order to permit time for additional consideration. If the rules are not significantly modified on reconsideration, we would be entitled to seek judicial review. In adopting the rules, the APSC indicated that affiliate transactions and financial arrangements currently in effect will be deemed in compliance until December 19, 2007, and that utilities may seek waivers of specific provisions of the rules. If the rules ultimately become effective as presently adopted, we would need to seek waivers from certain provisions of the rules or would be required to make significant modifications to existing practices, which could include the formation of and transfer of assets to subsidiaries.

If this regulatory framework becomes effective, it could have adverse impacts on our ability to operate and provide cost-effective utility service.

Texas. In September 2006, Gas Operations filed Statements of Intent (SOI) with 47 cities in its Texas coast service territory to increase miscellaneous service charges and to allow recovery of the costs of financial hedging transactions through its purchased gas cost adjustment. In November 2006, these changes became effective as all 47 cities either approved the filings or took no action, thereby allowing rates to go into effect by operation of law. In December 2006, Gas Operations filed a SOI with the Railroad Commission seeking to implement such changes in the environs of the Texas coast service territory. Gas Operations' filing has been suspended to allow for discovery and pre-hearing conferences, and a final determination is expected in the second quarter of 2007.

Minnesota. At September 30, 2006, Gas Operations had recorded approximately $45 million as a regulatory asset related to prior years' unrecovered purchased gas costs in its Minnesota service territory. Of the total, approximately $24 million related to the period from July 1, 2004 through June 30, 2006, and approximately $21 million related to the period from July 1, 2000 through June 30, 2004. The amounts related to periods prior to July 1, 2004 arose as a result of revisions to the calculation of unrecovered purchased gas costs previously approved by the Minnesota Public Utilities Commission (MPUC). Recovery of this regulatory asset was dependent upon obtaining a waiver from the MPUC rules. In November 2006, the MPUC considered the request for variance and voted to deny the waiver. Accordingly, we charged $21 million before income taxes to earnings in the fourth quarter of 2006 and reduced the regulatory asset by an equal amount. In February 2007, the MPUC denied reconsideration. Although no prediction can be made as to the ultimate outcome of this matter, we expect to appeal the MPUC's decision which precludes recovery of the cost of this gas, which was delivered to our customers and for which we have never been paid.

In November 2005, we filed a request with the MPUC to increase annual rates by approximately $41 million. In December 2005, the MPUC approved an interim rate increase of approximately $35 million that was implemented January 1, 2006. Any excess of amounts collected under the interim rates over the amounts approved in final rates is subject to refund to customers. In October 2006, the MPUC considered the request and indicated that it would grant a rate increase of approximately $21 million. In addition, the MPUC approved a $5 million affordability program to assist low-income customers, the actual cost of which will be recovered in rates in addition to the $21 million rate increase. Although the Minnesota Attorney General's Office (OAG) requested reconsideration of certain parts of the MPUC's decision, in January 2007, the MPUC voted to deny reconsideration and a final order was issued in January 2007. The proportional share of the excess of the amounts collected in interim rates over the amount allowed by the final order will be refunded to customers after implementation of final rates. We expect final rates to be implemented no later than May 2007. As of December 31, 2006, approximately $12 million has been accrued for the refund.

In December 2004, the MPUC opened an investigation to determine whether our practices regarding restoring natural gas service during the period between October 15 and April 15 (Cold Weather Period) were in compliance with the MPUC's Cold Weather Rule (CWR), which governs disconnection and reconnection of customers during the Cold Weather Period. In June 2005, the OAG issued its report alleging we had violated the CWR and recommended a $5 million penalty. In addition, in June 2005, we were named in a suit filed in the United States District Court, District of Minnesota on behalf of a purported class of customers who allege that our conduct under the CWR was in violation of the law. In August 2006, the court gave final approval to a $13.5 million settlement which resolved all but one small claim against us which have or could have been asserted by residential natural gas customers in the CWR class action. The agreement was also approved by the MPUC, resolving the claims made by the OAG. The anticipated costs of this settlement were accrued during the fourth quarter of 2005.

Department of Transportation

In December 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (2002 Act). This legislation applies to our interstate pipelines as well as our intrastate pipeline and local distribution companies. The legislation imposes several requirements related to ensuring pipeline safety and integrity. It requires pipeline and distribution companies to assess the integrity of their pipeline transmission facilities in areas of high population concentration or High Consequence Areas (HCA). The legislation further requires companies to perform remediation activities in accordance with the requirements of the legislation over a 10-year period.

In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, which reauthorized the programs adopted under the 2002 Act, proposed enhancements for state programs to reduce excavation damage to pipelines, established increased federal enforcement of one-call excavation programs, and established a new program for review of pipeline security plans and critical facility inspections. In addition, beginning in October 2005, the Pipeline and Hazardous Materials Safety Administration of the DOT commenced a rulemaking proceeding to develop rules that would better distinguish onshore gathering lines from production facilities and transmission lines, and to develop safety requirements better tailored to gathering line risks. In March 2006, the DOT revised its regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in non-rural areas, and adopt new compliance deadlines.

We anticipate that compliance with these regulations by our interstate and intrastate pipelines and our natural gas distribution companies will require increases in both capital and operating costs. The level of expenditures required to comply with these regulations will be dependent on several factors, including the age of the facility, the pressures at which the facility operates and the number of facilities deemed to be located in areas designated as HCA. Based on our interpretation of the rules and preliminary technical reviews, we believe compliance will require average annual expenditures of approximately $15 to $20 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 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.

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 or results of operations. 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.

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

Hydrocarbon Contamination. We and certain of our subsidiaries are among the defendants in lawsuits filed beginning in August 2001 in Caddo Parish and Bossier Parish, Louisiana. The suits allege that, at some unspecified date prior to 1985, the defendants allowed or caused hydrocarbon or chemical contamination of the Wilcox Aquifer, which lies beneath property owned or leased by certain of the defendants and which is the sole or primary drinking water aquifer in the area. The primary source of the contamination is alleged by the plaintiffs to be a gas processing facility in Haughton, Bossier Parish, Louisiana known as the “Sligo Facility,” which was formerly operated by our predecessor in interest. This facility was purportedly used for gathering natural gas from surrounding wells, separating liquid hydrocarbons from the natural gas for marketing, and transmission of natural gas for distribution.

Beginning about 1985, our predecessors engaged in a voluntary remediation of any subsurface contamination of the groundwater below the property they owned or leased. This work has been done in conjunction with and under the direction of the Louisiana Department of Environmental Quality. The plaintiffs seek monetary damages for alleged damage to the aquifer underlying their property, including the cost of restoring their property to its original condition and damages for diminution of value of their property. In addition, plaintiffs seek damages for trespass, punitive, and exemplary damages. The parties have reached an agreement on terms of a settlement in principle of this matter. That settlement would require approval from the Louisiana Department of Environmental Quality of an acceptable remediation plan that could be implemented by us. We are currently seeking that approval. If the currently agreed terms for settlement are ultimately implemented, we do not expect the ultimate cost associated with resolving this matter to have a material impact on our financial condition, results of operations or cash flows.

Manufactured Gas Plant Sites. We and our predecessors operated manufactured gas plants (MGP) 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, 2006, we had accrued $14 million for remediation of these Minnesota sites. At December 31, 2006, 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. 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, 2006, 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 two lawsuits, one filed in the United States District Court, District of Maine and the other filed in the Middle District of Florida, Jacksonville Division, 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 one of the lawsuits. In March 2005, the federal district court considering the suit for contribution in Florida granted our motion to dismiss on the grounds that we were not an “operator” of the site as had been alleged. In October 2006, the 11th Circuit Court of Appeals affirmed the district court’s dismissal. In June 2006, the federal district court in Maine that is considering the other suit 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 these sites and the range of environmental expenditures for potential remediation. However, we believe we are not liable as a former owner or operator of those sites under CERCLA and applicable state statutes, and are vigorously contesting those suits 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.

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, 2006, we had 4,990 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	4,147	1,466
Competitive Natural Gas Sales and Services	103	—
Interstate Pipelines	555	—
Field Services	185	—
Total	4,990	1,466

As of December 31, 2006, approximately 29% of our employees are subject to collective bargaining agreements. One agreement, covering approximately 5% of our employees, is covered by a collective bargaining unit agreement with the International Brotherhood of Electrical Workers Local 949, which expires in December 2007. We have a good relationship with this bargaining unit and expect to renegotiate new agreements in 2007.

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.

Our rates for our local distribution companies 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 alternative energy sources, which could result in us 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, 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.

Our natural gas distribution and competitive natural gas sales and services businesses are subject to fluctuations in natural gas pricing levels, which could affect the ability of our suppliers and customers to meet their obligations or otherwise adversely affect our liquidity.

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, on the regulated side, 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 apply downward demand pressure on natural gas consumption in the areas in which we operate and 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.

If we were to fail to renegotiate a contract with one of our significant pipeline customers or if we renegotiate the contract on less favorable terms, there could be an adverse impact on our operations.

Since October 31, 2006, our contract with Laclede Gas Company (Laclede), one of our pipeline's customers, has been terminable upon one year's prior notice. We have not received a termination notice and are currently negotiating a long-term contract with Laclede. If Laclede were to terminate this contract or if we were to renegotiate this contract at rates substantially lower than the rates provided in the current contract, there could be an adverse effect on our results of operations, financial condition and cash flows.

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, we might be unable to obtain the necessary natural gas to meet our obligations to customers, and our results of operations, financial condition and cash flows would be adversely affected.

The revenues and results of operations of our interstate pipelines and field services businesses are subject to fluctuations in the supply 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. 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 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 construction costs of proposed pipelines and related compression facilities may be significantly higher than our current estimates.

Our subsidiaries are involved in significant pipeline construction projects. The construction of new pipelines and related compression facilities requires the expenditure of significant amounts of capital, which may exceed our estimates. If we undertake these projects, they may not be completed at the budgeted 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, 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 those under the 1935 Act regarding organization, financing and affiliate transactions that could have significant adverse effects on our ability to operate.

In Arkansas, the APSC in December 2006 adopted rules governing affiliate transactions involving public utilities operating in Arkansas. The rules treat as affiliate transactions all transactions between our Arkansas utility operations and our other divisions, as well as transactions between the Arkansas utility operations and our affiliates. All such affiliate transactions are required to be priced under an asymmetrical pricing formula under which the Arkansas utility operations would benefit from any difference between the cost of providing goods and services to or from the Arkansas utility operations and the market value of those goods or services. Additionally, the Arkansas utility operations are not permitted to participate in any financing other than to finance retail utility operations in Arkansas, which would preclude continuation of existing financing arrangements in which we finance our divisions and subsidiaries, including our Arkansas utility operations.

Although the Arkansas rules are now in effect, we and other gas and electric utilities operating in Arkansas sought reconsideration of the rules by the APSC. In February 2007, the APSC granted that reconsideration and suspended operation of the rules in order to permit time for additional consideration. If the rules are not significantly modified on reconsideration, we would be entitled to seek judicial review. In adopting the rules, the APSC indicated that affiliate transactions and financial arrangements currently in effect will be deemed in compliance until December 19, 2007, and that utilities may seek waivers of specific provisions of the rules. If the rules ultimately become effective as presently adopted, we would need to seek waivers from certain provisions of the rules or would be required to make significant modifications to existing practices, which could include the formation of and transfer of assets to subsidiaries.

In Minnesota, a bill has been introduced during the current session of the legislature that would create a regulatory scheme for public utility holding companies like CenterPoint Energy and their public utility operations in Minnesota. The proposed legislation would restrict financing activities, affiliate arrangements between the Minnesota utility operations and the holding company and other utility and non-utility operations within the holding company and acquisitions and divestitures. In addition, the bill would require prior MPUC approval of dividends paid by the holding company, in addition to dividends paid by its utility subsidiaries, and would limit the level of non-utility investments of the holding company.

If either or both of these regulatory frameworks become effective, they could have adverse effects on our ability to operate and to provide cost-effective utility service. In addition, if more than one state adopts restrictions like those proposed in Arkansas and Minnesota, 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, 2006, we had $2.3 billion of outstanding indebtedness on a consolidated basis. As of December 31, 2006, approximately $320 million principal amount of this debt must be paid through 2009. Our future financing activities may depend, at least in part, on:

- general economic and capital market conditions;
- credit availability from financial institutions and other lenders;
- investor confidence in us and the market in which we operate;
- maintenance of acceptable credit ratings;
- market expectations regarding our future earnings and probable 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 ratings and credit may be impacted by CenterPoint Energy's credit standing. As of December 31, 2006, CenterPoint Energy and its other subsidiaries have approximately $555 million principal amount of debt required to be paid through 2009. This amount excludes amounts related to capital leases, transition bonds and indexed debt securities obligations. In addition, CenterPoint Energy has cash settlement obligations with respect to $575 million of outstanding 3.75% convertible notes on which holders could exercise their conversion rights during the first quarter of 2007 and in subsequent quarters in which CenterPoint Energy's common stock price causes such notes to be convertible. 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 negatively impact our results of operations and those of our subsidiaries.

We use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. We 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 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.

Risks Common to Our Businesses and Other Risks

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

Our operations are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of natural gas pipelines and distribution systems, 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.

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 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 is unable to satisfy a liability that has been so assumed in circumstances in which Reliant Energy has not been released from the liability in connection with the transfer, we or 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 CenterPoint Energy and us against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for our benefit and that of CenterPoint Energy, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. We currently hold letters of credit in the amount of $33.3 million issued on behalf of RRI against guaranties that have not been released. Our current exposure under the guaranties relates to our guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. RRI continues to meet its obligations under the transportation contracts, and we believe current market conditions make those contracts valuable for transportation services in the near term. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, our exposure to the counterparty under the guaranty could exceed the security provided by RRI. We have requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of our obligations under the guaranty. In June 2006, we and the RRI trading subsidiary jointly filed a complaint at the FERC against the counterparty on our guaranty. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security demanded by the counterparty exceeds the level permitted by the FERC's policies. The complaint asks the FERC to require the counterparty to release us from our guaranty obligation and, in its place, accept (i) a guaranty from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit limited to (A) one year of demand charges for a transportation agreement related to a 2003 expansion of the counterparty's pipeline, and (B) three months of demand charges for three other transportation agreements held by the RRI trading subsidiary. The counterparty has argued that the amount of the guaranty does not violate the FERC's policies and that the proposed substitution of credit support is not authorized under the counterparty's financing documents or required by the FERC's policy. The parties have now completed their submissions to FERC regarding the complaint. We cannot predict what action the FERC may take on the complaint or when the FERC may rule. In addition to the FERC proceeding, in February 2007 we and CenterPoint Energy made a formal demand on RRI under procedures provided for by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy and RRI. That demand seeks to resolve the disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. It is possible that this demand could lead to an arbitration proceeding between the companies, but when and on what terms the disagreement with RRI will ultimately be resolved cannot be predicted.

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 CenterPoint Energy as its former owner.

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 — 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 — 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 —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 — 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 8(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 2005 and 2006, 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 2.25, 1.99, 2.20, 2.64 and 2.67 for the years ended December 31, 2002, 2003, 2004, 2005 and 2006, 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 are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy). We own and operate natural gas distribution systems in six states. Our wholly owned subsidiaries own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. Another 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.

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, 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 are subject to rate regulation and are reported in the Natural Gas Distribution business segment. Beginning in the fourth quarter of 2006, we are reporting our interstate pipelines and field services businesses as two separate business segments, Interstate Pipelines business segment and Field Services business segment. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. A summary of our reportable business segments as of December 31, 2006 is set forth below:

Natural Gas Distribution

We own and operate our regulated natural gas distribution business, 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 7,900 miles of gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. This business also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.2 billion cubic feet (Bcf) per day and a combined working gas capacity of approximately 59.0 Bcf. Most storage operations are in north Louisiana and Oklahoma. This business has begun construction of two significant pipeline additions, in one case as part of a joint venture.

Field Services

Our field services business owns and operates approximately 3,700 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 2006 and 2007

Debt Financing Transactions

In March 2006, we replaced our $400 million five-year revolving credit facility with a $550 million five-year revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 45 basis points based on our current credit ratings, as compared to LIBOR plus 55 basis points for borrowings under the facility it replaced. An additional utilization fee of 10 basis points applies to borrowings any time more than 50% of the facility is utilized, and the spread to LIBOR fluctuates based on our credit rating.

In May 2006, we issued $325 million aggregate principal amount of senior notes due in May 2016 with an interest rate of 6.15%. The proceeds from the sale of the senior notes were used for general corporate purposes, including repayment or refinancing of debt (including $145 million of our 8.90% debentures repaid December 15, 2006), capital expenditures and working capital.

In February 2007, we issued $150 million aggregate principal amount of senior notes due in February 2037 with an interest rate of 6.25%. The proceeds from the sale of the senior notes were used to repay advances for the purchase of receivables under our $375 million receivables facility. Such repayment provides increased liquidity and capital resources for our general corporate purposes.

Interstate Pipeline Expansion

Carthage to Perryville. In October 2005, CEGT signed a 10-year firm transportation agreement with XTO Energy (XTO) to transport 600 million cubic feet (MMcf) per day of natural gas from Carthage, Texas to CEGT's Perryville hub in Northeast Louisiana. To accommodate this transaction, CEGT filed a certificate application with the FERC in March 2006 to build a 172-mile, 42-inch diameter pipeline and related compression facilities. The capacity of the pipeline under this filing will be 1.25 Bcf per day. CEGT has signed firm contracts for the full capacity of the pipeline.

In October 2006, the FERC issued CEGT's certificate to construct, own and operate the pipeline and compression facilities. CEGT has begun construction of the facilities and expects to place the facilities in service in the second quarter of 2007 at a cost of approximately $500 million.

Based on interest expressed during an open season held in 2006, and subject to FERC approval, CEGT may expand capacity of the pipeline to 1.5 Bcf per day, which would bring the total estimated capital cost of the project to approximately $550 million. In September 2006, CEGT filed for approval to increase the maximum allowable operating pressure with the U.S. Department of Transportation. In December 2006, CEGT filed for the necessary certificate to expand capacity of the pipeline with the FERC. CEGT expects to receive the approvals in the third quarter of 2007.

During the four-year period subsequent to the in-service date of the pipeline, XTO can request, and subject to mutual negotiations that meet specific financial parameters and to FERC approval, CEGT would construct a 67-mile extension from CEGT's Perryville hub to an interconnect with Texas Eastern Gas Transmission at Union Church, Mississippi.

Southeast Supply Header. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., our wholly owned subsidiary, and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture (Southeast Supply Header or SESH) to construct, own and operate a 270-mile pipeline that will extend from CEGT's Perryville hub in northeast Louisiana to Gulfstream Natural Gas System, which is 50 percent owned by an affiliate of Spectra. In August 2006, the joint venture signed an agreement with Florida Power & Light Company (FPL) for firm transportation services, which subscribed approximately half of the planned 1 Bcf per day capacity of the pipeline. FPL's commitment was contingent on the approval of the FPL contract by the Florida Public Service Commission, which was received in December 2006. Subject to the joint venture receiving a certificate from the FERC to construct, own and operate the pipeline, subsidiaries of Spectra and us have committed to build the pipeline. In December 2006, the joint venture signed agreements with affiliates of Progress Energy Florida, Southern Company, Tampa Electric Company, and EOG Resources, Inc. bringing the total subscribed capacity to 945 MMcf per day. Additionally, SESH and Southern Natural Gas (SNG) have executed a definitive agreement that provides for SNG to jointly own the first 115 miles of the pipeline. Under the agreement, SNG will own an undivided interest in the portion of the pipeline from Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter will be increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that could increase the capacity up to 500 MMcf per day. An application to construct, own and operate the pipeline was filed with the FERC in December 2006. Subject to receipt of FERC authorization and construction in accordance with planned schedule, we currently expect an in service date in the summer of 2008. The total cost of the combined project is estimated to be $800 to $900 million with SESH's net costs of $700 to $800 million after SNG's contribution.

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, changes in or application of laws or regulations applicable to other aspects of our business;

- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;
- 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;
- the timing and extent of changes in natural gas basis differentials;
- changes in interest rates or rates of inflation;
- weather variations and other natural phenomena;
- the timing and extent of changes in the supply of natural gas;
- 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;
- the ability of Reliant Energy, Inc. (RRI) to satisfy its obligations to us;
- the outcome of litigation brought for 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 provide the anticipated benefits to us; and
- other factors we discuss under “Risk Factors” in Item 1A of this report.

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. 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, 2004, 2005 and 2006, 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,		
	2004	2005	2006
Revenues	$ 6,472	$ 8,070	$ 7,528
Expenses:			
Natural gas	5,013	6,509	5,909
Operation and maintenance	732	743	798
Depreciation and amortization	187	198	200
Taxes other than income taxes	147	156	149
Total	6,079	7,606	7,056
Operating Income	393	464	472
Interest and other finance charges	(178)	(176)	(167)
Other income, net	16	21	18
Income Before Income Taxes	231	309	323
Income Tax Expense	87	116	116
Net Income	$ 144	$ 193	$ 207

2006 Compared to 2005. We reported net income of $207 million for 2006 as compared to $193 million for 2005. The increase in net income of $14 million was primarily due to a $19 million increase in operating income from our Field Services business segment, a $17 million increase in operating income from our Competitive Natural Gas Sales and Services business segment, a $16 million increase in operating income from our Interstate Pipelines business segment and a decrease in interest expense of $9 million, partially offset by a decrease in operating income from our Natural Gas Distribution business segment of $51 million.

Our effective tax rate for 2006 and 2005 was 36.1% and 37.4%, respectively.

2005 Compared to 2004. We reported net income of $193 million for 2005 as compared to $144 million for 2004. The increase in net income of $49 million was primarily due to increased operating income of $36 million in our Interstate Pipelines business segment, a $19 million increase in operating income from our Field Services business segment, and a $16 million increase in operating income from our Competitive Natural Gas Sales and Services business segment, partially offset by a $29 million increase in income tax expense in 2005 as compared to 2004.

Our effective tax rate for 2005 and 2004 was 37.4% and 37.5%, respectively.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table present operating income (in millions) for each of our business segments for 2004, 2005 and 2006. Due to the change in reportable segments in the fourth quarter of 2006, we have recast our segment information for 2004 and 2005 to conform to the 2006 presentation. The segment detail revised as a result of the new reportable business segments did not affect consolidated operating income for any year. 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,		
	2004	2005	2006
Natural Gas Distribution	$ 178	$ 175	$ 124
Competitive Natural Gas Sales and Services	44	60	77
Interstate Pipelines	129	165	181
Field Services	51	70	89
Other Operations	(9)	(6)	1
Total Consolidated Operating Income	$ 393	$ 464	$ 472

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2004, 2005 and 2006 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2004	2005	2006
Revenues	$ 3,579	$ 3,846	$ 3,593
Expenses:			
Natural gas	2,596	2,841	2,598
Operation and maintenance	544	551	594
Depreciation and amortization	141	152	152
Taxes other than income taxes	120	127	125
Total expenses	3,401	3,671	3,469
Operating Income	$ 178	$ 175	$ 124
Throughput (in billion cubic feet (Bcf)):			
Residential	175	160	152
Commercial and industrial	237	215	224
Total Throughput	412	375	376
Average number of customers:			
Residential	2,798,352	2,839,947	2,883,927
Commercial and industrial	245,926	244,782	243,265
Total	3,044,278	3,084,729	3,127,192

2006 Compared to 2005. Our Natural Gas Distribution business segment reported operating income of $124 million for 2006 as compared to $175 million for 2005. Decreases in operating margins (revenues less natural gas costs) include a $21 million write-off in the fourth quarter of 2006 of purchased gas costs for periods prior to July 2004, the recovery of which was denied by the Minnesota Public Utilities Commission (MPUC), and the impact of milder weather and decreased usage ($30 million). These decreases were partially offset by higher margins from rate and service charge increases and rate design changes ($35 million), along with the addition of over 42,000 customers in 2006 ($9 million). Operation and maintenance expenses increased primarily as a result of costs associated with staff reductions ($17 million), benefit costs increases ($6 million), higher costs of goods and services ($8 million) and higher bad debt expenses ($10 million), partially offset by higher litigation reserves recorded in 2005 ($11 million).

2005 Compared to 2004. Our Natural Gas Distribution business segment reported operating income of $175 million for 2005 as compared to $178 million for 2004. Increases in operating margins from rate increases ($19 million) and margin from gas exchanges ($7 million) were partially offset by the impact of milder weather and decreased throughput net of continued customer growth with the addition of approximately 44,000 customers in 2005 ($13 million). Operation and maintenance expense increased $7 million. Excluding an $8 million charge recorded in 2004 for severance costs associated with staff reductions, operation and maintenance expenses increased by $15 million primarily due to increased litigation reserves ($11 million) and increased bad debt expense ($9 million), partially offset by the capitalization of previously incurred restructuring expenses as allowed by a regulatory order from the Railroad Commission of Texas ($5 million). Additionally, operating income was unfavorably impacted by increased depreciation expense primarily due to higher plant balances ($11 million).

During the third quarter of 2005, our east Texas, Louisiana and Mississippi natural gas service areas were affected by Hurricanes Katrina and Rita. Damage to our facilities was limited, but approximately 10,000 homes and businesses were damaged to such an extent that they were not able to, and in some cases continue to be unable to, take service. The impact on the Natural Gas Distribution business segment's operating income was not material.

Competitive Natural Gas Sales and Services

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for 2004, 2005 and 2006 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2004	2005	2006
Revenues	$ 2,848	$ 4,129	$ 3,651
Expenses:			
Natural gas	2,778	4,033	3,540
Operation and maintenance	22	30	30
Depreciation and amortization	2	2	1
Taxes other than income taxes	2	4	3
Total expenses	2,804	4,069	3,574
Operating Income	$ 44	$ 60	$ 77
Throughput (in Bcf):			
Wholesale – third parties	228	304	335
Wholesale – affiliates	35	27	36
Retail	141	156	149
Pipeline	76	51	35
Total Throughput	480	538	555
Average number of customers:			
Wholesale	97	138	140
Retail	5,976	6,328	6,452
Pipeline	172	142	138
Total	6,245	6,608	6,730

2006 Compared to 2005. Our Competitive Natural Gas Sales and Services business segment reported operating income of $77 million for 2006 as compared to $60 million for 2005. The increase in operating income of $17 million was primarily driven by improved operating margins (revenues less natural gas costs) resulting from seasonal price differentials and favorable basis differentials over the pipeline capacity that we control ($44 million) and a favorable change in unrealized gains resulting from mark-to-market accounting ($37 million), partially offset by write-downs of natural gas inventory to the lower of average cost or market ($66 million).

2005 Compared to 2004. Our Competitive Natural Gas Sales and Services business segment reported operating income of $60 million for 2005 as compared to $44 million for 2004. The increase in operating income of $16 million was primarily due to increased operating margins (revenues less natural gas costs) related to higher sales to utilities and favorable basis differentials over the pipeline capacity that we control ($32 million) less the impact of certain derivative transactions ($6 million), partially offset by higher payroll and benefit related expenses ($4 million) and increased bad debt expense ($3 million).

Interstate Pipelines

The following table provides summary data of our Interstate Pipelines business segment for 2004, 2005 and 2006 (in millions, except throughput data):

	Year Ended December 31,		
	2004	2005	2006
Revenues	$ 368	$ 386	$ 388
Expenses:			
Natural gas	58	47	31
Operation and maintenance	131	121	120
Depreciation and amortization	36	36	37
Taxes other than income taxes	14	17	19
Total expenses	239	221	207
Operating Income	$ 129	$ 165	$ 181
Throughput (in Bcf):			
Transportation	859	914	939
Other	4	2	1
Total Throughput	863	916	940

2006 Compared to 2005. Our Interstate Pipelines business segment reported operating income of $181 million for 2006 as compared to $165 million for 2005. Operating margins (revenues less natural gas costs) increased by $18 million. This increase was driven primarily by increased demand for transportation services and ancillary services ($15 million). Operation and maintenance expenses decreased by $1 million primarily due to the gain on sale of excess gas during 2006 ($18 million) combined with lower litigation reserves ($6 million) in 2006 compared to 2005. These favorable variances were partially offset by a write-off of expenses associated with the Mid-Continent Crossing pipeline project which was discontinued in 2006 ($11 million) as well as increased operating expenses ($11 million) largely associated with staffing increases and costs associated with continued compliance with pipeline integrity regulations.

2005 Compared to 2004. Our Interstate Pipelines business segment reported operating income of $165 million compared to $129 million in 2004. Operating margins (revenues less natural gas costs) increased by $29 million. The increase was primarily related to increased demand for certain transportation services driven by commodity price volatility as well as favorable pricing on certain transportation deliveries driven by favorable basis differentials relative to competing supply areas ($42 million). These favorable margin variances were partially offset by lower project-related revenues ($11 million). Operation and Maintenance expenses decreased by $10 million primarily due to lower cost incurred in support of project-related revenues ($9 million).

Field Services

The following table provides summary data of our Field Services business segment for 2004, 2005 and 2006 (in millions, except throughput data):

	Year Ended December 31,		
	2004	2005	2006
Revenues	$ 92	$ 120	$ 150
Expenses:			
Natural gas	(9)	(10)	(10)
Operation and maintenance	40	49	59
Depreciation and amortization	8	9	10
Taxes other than income taxes	2	2	2
Total expenses	41	50	61
Operating Income	$ 51	$ 70	$ 89
Throughput (in Bcf):			
Gathering	321	353	375

2006 Compared to 2005. Our Field Services business segment reported operating income of $89 million for 2006 as compared to $70 million for 2005. The increase of $19 million was driven by increased gas gathering and ancillary services, which reflects contributions from new facilities placed in service ($27 million) and higher commodity prices ($3 million), partially offset by higher operation and maintenance expenses ($10 million).

Equity income from the jointly-owned gas processing plant was $6 million for each of the years 2006 and 2005 and is included in other income.

2005 Compared to 2004. Our Field Services business segment reported operating income of $70 million for 2005 compared to $51 million in 2004. The increase of $19 million was driven by increased gas gathering and ancillary services ($22 million) and higher commodity prices ($7 million), partially offset by higher operation and maintenance expenses ($9 million).

Equity income from the jointly-owned gas processing plant was $6 million and $2 million for the years 2005 and 2004, respectively, and is included in other income.

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, and working capital needs. Our principal cash requirements during 2007 are approximately $614 million of capital expenditures and $7 million of maturing long-term debt.

We expect that the long-term debt securities issued in the first quarter of 2007, borrowings under our credit facility, anticipated cash flows from operations and borrowings from affiliates will be sufficient to meet our cash needs for the next twelve months. Cash needs may also be met by issuing equity or debt securities in the capital markets.

The following table sets forth our capital expenditures for 2006 and estimates of our capital requirements for 2007 through 2011 (in millions):

	2006	2007	2008	2009	2010	2011
Natural Gas Distribution	$ 187	$ 208	$ 217	$ 202	$ 207	$ 212
Competitive Natural Gas Sales and Services	18	18	12	12	12	12
Interstate Pipelines	437	272	269	45	54	62
Field Services	65	116	86	85	85	85
Total	$ 707	$ 614	$ 584	$ 344	$ 358	$ 371

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

Contractual Obligations	Total	2007	2008-2009	2010-2011	2012 and thereafter
Long-term debt, including current portion	$ 2,162	$ 7	$ 313	$ 563	$ 1,279
Interest payments — other long-term debt (1)	1,168	160	299	266	443
Operating leases(2)	69	16	25	14	14
Benefit obligations(3)	—	—	—	—	—
Purchase obligations(4)	181	181	—	—	—
Non-trading derivative liabilities	221	141	44	36	—
Other commodity commitments(5)	3,044	922	504	412	1,206
Total contractual cash obligations	$ 6,845	$ 1,427	$ 1,185	$ 1,291	$ 2,942

(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, 2006. 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 8(b) to our consolidated financial statements.

(3) We expect to contribute approximately $19 million to our postretirement benefits plan in 2007 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 new 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 8(a) to our consolidated financial statements.

Arkansas Public Service Commissions, Affiliate Transaction Rulemaking Proceeding. In Arkansas, the APSC in December 2006 adopted rules governing affiliate transactions involving public utilities operating in Arkansas. The rules treat as affiliate transactions all transactions between our Arkansas utility operations and other divisions of ours, as well as transactions between the Arkansas utility operations and our affiliates. All such affiliate transactions are required to be priced under an asymmetrical pricing formula under which the Arkansas utility operations would benefit from any difference between the cost of providing goods and services to or from the Arkansas utility operations and the market value of those goods or services. Additionally, the Arkansas utility operations are not permitted to participate in any financing other than to finance retail utility operations in Arkansas, which would preclude continuation of existing financing arrangements in which we finance our divisions and subsidiaries, including our Arkansas utility operations.

Although the Arkansas rules are now in effect, we and other gas and electric utilities operating in Arkansas sought reconsideration of the rules by the APSC. In February 2007, the APSC granted that reconsideration and suspended operation of the rules in order to permit time for additional consideration. If the rules are not significantly modified on reconsideration, we would be entitled to seek judicial review. In adopting the rules, the APSC indicated that affiliate transactions and financial arrangements currently in effect will be deemed in compliance until December 19, 2007, and that utilities may seek waivers of specific provisions of the rules. If the rules ultimately become effective as presently adopted, we would need to seek waivers from certain provisions of the rules or would be required to make significant modifications to existing practices, which could include the formation of and transfer of assets to subsidiaries.

If this regulatory framework becomes effective, it could have adverse impacts on our ability to operate and provide cost-effective utility service.

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 CenterPoint Energy and us against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for our benefit ant that of CenterPoint Energy, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. We currently hold letters of credit in the amount of $33.3 million issued on behalf of RRI against guaranties that have not been released. Our current exposure under the guaranties relates to our guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. RRI continues to meet its obligations under the transportation contracts, and we believe current market conditions make those contracts valuable for transportation services in the near term. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, our exposure to the counterparty under the guaranty could exceed the security provided by RRI. We have requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of our obligations under the guaranty. In June 2006, we and the RRI trading subsidiary jointly filed a complaint at the FERC against the counterparty on our guaranty. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security demanded by the counterparty exceeds the level permitted by the FERC's policies. The complaint asks the FERC to require the counterparty to release us from our guaranty obligation and, in its place, accept (i) a guaranty from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit limited to (A) one year of demand charges for a transportation agreement related to a 2003 expansion of the counterparty's pipeline, and (B) three months of demand charges for three other transportation agreements held by the RRI trading subsidiary. The counterparty has argued that the amount of the guaranty does not violate the FERC's policies and that the proposed substitution of credit support is not authorized under the counterparty's financing documents or required by the FERC's policy. The parties have now completed their submissions to FERC regarding the complaint. We cannot predict what action the FERC may take on the complaint or when the FERC may rule. In addition to the FERC proceeding, in February 2007 we and CenterPoint Energy made a formal demand on RRI under procedures provided for by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc. That demand seeks to resolve the disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. It is possible that this demand could lead to an arbitration proceeding between the companies, but when and on what terms the disagreement with RRI will ultimately be resolved cannot be predicted.

Senior Notes. In May 2006, we issued $325 million aggregate principal amount of senior notes due in May 2016 with an interest rate of 6.15%. The proceeds from the sale of the senior notes were used for general corporate purposes, including repayment or refinancing of debt (including $145 million of our 8.90% debentures repaid December 15, 2006), capital expenditures and working capital.

In February 2007, we issued $150 million aggregate principal amount of senior notes due in February 2037 with an interest rate of 6.25%. The proceeds from the sale of the senior notes were used to repay advances for the purchase of receivables under our $375 million receivables facility. Such repayment provides increased liquidity and capital resources for general corporate purposes.

Credit Facilities. In March 2006, we replaced our $400 million five-year revolving credit facility with a $550 million five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 45 basis points based on our current credit ratings, as compared to LIBOR plus 55 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt to total capitalization covenant of 65%.

Under the credit facility, an additional utilization fee of 10 basis points applies to borrowings any time more than 50% of the facility is utilized, and the spread to LIBOR fluctuates 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. We are currently in compliance with the various business and financial covenants contained in the credit facility.

In October 2006, the termination date of our receivables facility was extended to October 2007. The facility size was $250 million until December 2006, is $375 million from December 2006 to May 2007 and ranges from $150 million to $325 million during the period from May 2007 to the October 30, 2007 termination date of the facility.

As of February 28, 2007, we had no borrowings and approximately $19 million of outstanding letters of credit under our $550 million credit facility.

Securities Registered with the SEC. At December 31, 2006, we had a shelf registration statement covering $500 million principal amount of debt securities. Following a February 2007 note issuance of $150 million, our shelf registration covered $350 million principal amount of senior debt securities.

Temporary Investments. As of February 28, 2007, 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 28, 2007, we had borrowings from the money pool aggregating $3 million. 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 28, 2007, Moody's Investors Service, Inc. (Moody's), Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies (S&P) and Fitch, Inc. (Fitch) had assigned the following credit ratings to our senior unsecured debt:

Moody's		S&P		Fitch	
Rating	Outlook(1)	Rating	Outlook(2)	Rating	Outlook(3)
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.

We cannot assure you that these 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, the willingness of suppliers to extend credit lines to us on an unsecured basis and the execution of our commercial strategies.

A decline in credit ratings could increase borrowing costs under our $550 million revolving 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 margins of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments.

CenterPoint Energy Services, Inc. (CES), a 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, 2006, the amount posted as collateral amounted to $113 million. Should our credit ratings 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, 2006, unsecured credit limits extended to CES by counterparties aggregate $133 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.

In connection with the development of the Southeast Supply Header, we have committed that we will advance funds to the joint venture or cause funds to be advanced, up to $400 million, for our 50 percent share of the cost to construct the pipeline. We also agreed to provide a letter of credit in the amount of our share of funds which have not been advanced in the event S&P reduces our bond rating below investment grade before we have advanced the required construction funds. However, we are relieved of these commitments (i) to the extent of 50 percent of any borrowing agreements that the joint venture has obtained and maintains for funding the construction of the pipeline and (ii) to the extent we or our subsidiary participating in the joint venture obtains committed borrowing agreements pursuant to which funds may be borrowed and used for the construction of the pipeline. A similar commitment has been provided by the other party to the joint venture.

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. Pursuant to the indenture governing CenterPoint Energy's senior notes, 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. As of February 28, 2007, CenterPoint Energy had issued six series of senior notes aggregating $1.4 billion in principal amount under this indenture. A default by CenterPoint Energy would not trigger a default under our debt instruments or bank credit facilities.

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

- cash collateral requirements that could exist in connection with certain contracts, including gas purchases, gas price hedging and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, particularly given gas price levels and volatility;
- acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of natural gas suppliers;
- increased costs related to the acquisition of natural gas;
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various regulatory actions;
- the ability of RRI and its subsidiaries to satisfy their obligations 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;
- the outcome of litigation brought by and against us;
- contributions to benefit plans;
- restoration costs and revenue losses resulting from natural disasters such as hurricanes; and
- various other risks identified in "Risk Factors" in Item 1A of this report.

Certain Contractual Limits on 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 percent.

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.

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 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, 2006. 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, 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 Interpretation No. 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 4%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by approximately 3%. At December 31, 2006, our estimated cost of retiring these assets was approximately $66 million.

Unbilled Revenues

Revenues related to the sale and/or delivery of natural gas are generally recorded when natural gas is delivered to customers. However, the determination of sales 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, amounts of natural gas delivered 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 Plan. As discussed in Note 2(o) to our consolidated financial statements, we participate in CenterPoint Energy’s qualified non-contributory pension plan covering substantially all employees. Pension expense for 2007 is estimated to be $5 million based on an expected return on plan assets of 8.5% and a discount rate of 5.85% as of December 31, 2006. Pension expense for the year ended December 31, 2006 was $16 million. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension 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 and other energy commodities risk.
- 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 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

We have outstanding long-term debt and bank loans that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $-0- and $187 million at December 31, 2005 and 2006, respectively. If the floating interest rates were to increase by 10% from December 31, 2006 rates, our combined interest expense would increase by approximately $1 million.

At December 31, 2005 and 2006, we had outstanding fixed-rate debt aggregating $2.0 billion and $2.2 billion, respectively, in principal amount and having a fair value of $2.2 billion and $2.3 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 6 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $59 million if interest rates were to decline by 10% from their levels at December 31, 2006. 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, 2006, the recorded fair value of our non-trading energy derivatives was a net liability of $102 million. The net liability consisted of a $153 million net liability associated with Gas Operations price stabilization activities partially offset by a net asset of $51 million related to our Competitive Natural Gas Sales and Services business. Net assets or liabilities related to Gas Operations 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, 2006 levels would have decreased the fair value of our non-trading energy derivatives by $80 million.

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

Our 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.

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) as of December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, cash flows and stockholder's equity for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations", effective December 31, 2005.

DELOITTE & TOUCHE LLP

Houston, Texas
March 9, 2007

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

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2004	2005	2006
		(In Millions)	
Revenues	$ 6,472	$ 8,070	$ 7,528
Expenses:			
Natural gas	5,013	6,509	5,909
Operation and maintenance	732	743	798
Depreciation and amortization	187	198	200
Taxes other than income taxes	147	156	149
Total	6,079	7,606	7,056
Operating Income	393	464	472
Other Income (Expense):			
Interest and other finance charges	(178)	(176)	(167)
Other, net	16	21	18
Total	(162)	(155)	(149)
Income Before Income Taxes	231	309	323
Income Tax Expense	87	116	116
Net Income	$ 144	$ 193	$ 207

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,		
	2004	2005	2006
		(In Millions)	
Net income	$ 144	$ 193	$ 207
Other comprehensive income (loss), net of tax:			
Net deferred gain from cash flow hedges (net of tax of $31, $9 and $11)	59	17	22
Reclassification of net deferred gain from cash flow hedges realized in net income (net of tax of ($12), ($5) and ($3))	(24)	(8)	(7)
Reclassification of deferred gain from de-designation of cash flow hedges to over/under recovery of gas costs (net of tax of ($37))	(68)	—	—
Other comprehensive income (loss)	(33)	9	15
Comprehensive income	$ 111	$ 202	$ 222

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, 2005	December 31, 2006
	(In Millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 31	$ 5
Accounts receivable, net	942	846
Accrued unbilled revenue	500	356
Accounts and notes receivable — affiliated companies	—	198
Inventory	323	336
Non-trading derivative assets	131	98
Taxes receivable	117	—
Deferred tax asset	17	2
Prepaid expenses	11	14
Other	119	346
Total current assets	2,191	2,201
Property, Plant and Equipment, Net	4,105	4,639
Other Assets:		
Goodwill	1,709	1,709
Non-trading derivative assets	104	21
Accounts and notes receivable — affiliated companies, net	9	—
Other	183	245
Total other assets	2,005	1,975
Total Assets	$ 8,301	$ 8,815
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ —	$ 187
Current portion of long-term debt	154	7
Accounts payable	1,077	928
Accounts and notes payable — affiliated companies	319	386
Taxes accrued	67	115
Interest accrued	46	48
Customer deposits	62	62
Non-trading derivative liabilities	43	141
Other	341	305
Total current liabilities	2,109	2,179
Other Liabilities:		
Accumulated deferred income taxes, net	663	662
Non-trading derivative liabilities	35	80
Benefit obligations	127	138
Other	716	669
Total other liabilities	1,541	1,549
Long-Term Debt	1,838	2,155
Commitments and Contingencies (Note 8)		
Stockholder's Equity	2,813	2,932
Total Liabilities And Stockholder's Equity	$ 8,301	$ 8,815

See Notes to the Company's Consolidated Financial Statements

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

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31, 2004	2005 (In Millions)	2006
Cash Flows from Operating Activities:			
Net income	$ 144	$ 193	$ 207
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	187	198	200
Deferred income taxes	(8)	32	16
Amortization of deferred financing costs	10	9	8
Write-down of natural gas inventory	—	—	66
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(163)	(393)	248
Accounts receivable/payable, affiliates	7	10	(19)
Inventory	(14)	(109)	(78)
Taxes receivable	118	39	—
Accounts payable	208	326	(262)
Fuel cost recovery	25	(129)	111
Interest and taxes accrued	11	(23)	(4)
Net non-trading derivative assets and liabilities	(39)	(12)	(18)
Margin deposits, net	12	51	(156)
Other current assets	(34)	(5)	(80)
Other current liabilities	(16)	54	29
Other assets	47	8	1
Other liabilities	(6)	30	19
Other, net	(3)	(3)	(15)
Net cash provided by operating activities	486	276	273
Cash Flows from Investing Activities:			
Capital expenditures	(269)	(403)	(599)
Decrease (increase) in affiliate notes receivable	(30)	42	—
Other, net	(3)	(11)	(22)
Net cash used in investing activities	(302)	(372)	(621)
Cash Flows from Financing Activities:			
Payments of long-term debt	—	(372)	(152)
Proceeds from long-term debt	—	—	324
Increase (decrease) in short-term borrowings, net	(63)	—	187
Increase (decrease) in notes with affiliates, net	—	288	(103)
Contribution from parent	—	171	168
Dividends to parent	(13)	(100)	(100)
Debt issuance costs	(1)	(1)	(1)
Other, net	—	—	(1)
Net cash provided by (used in) financing activities	(77)	(14)	322
Net Increase (Decrease) in Cash and Cash Equivalents	107	(110)	(26)
Cash and Cash Equivalents at Beginning of the Year	34	141	31
Cash and Cash Equivalents at End of the Year	$ 141	$ 31	$ 5
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 176	$ 181	$ 162
Income taxes (refunds)	42	87	(25)
Non-cash transactions:			
Increase in accounts payable related to capital expenditures	$ —	$ 14	$ 108

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

	2004		2005		2006	
	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		1,985		2,232		2,404
Contribution from (to) parent		247		171		(3)
Other		—		1		2
Balance, end of year		2,232		2,404		2,403
Retained Earnings						
Balance, beginning of year		174		305		398
Net income		144		193		207
Dividend to parent		(13)		(100)		(100)
Balance, end of year		305		398		505
Accumulated Other Comprehensive Income						
Balance, end of year:						
Net deferred gain from cash flow hedges		2		11		26
SFAS No. 158 incremental effect		—		—		(2)
Total accumulated other comprehensive income, end of year		2		11		24
Total Stockholder's Equity		$ 2,539		$ 2,813		$ 2,932

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 and Basis of Presentation

CenterPoint Energy Resources Corp. (CERC Corp., and, together with its subsidiaries, the Company), owns and operates natural gas distribution systems in six states. Wholly owned subsidiaries of the Company own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. Another 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.

Basis of Presentation

For a description of the Company's reportable business segments, see Note 11.

2. Summary of Significant Accounting Policies

(a) Reclassifications and Use of Estimates

Segment information for 2004 and 2005 has been recast to conform to the 2006 presentation due to the change in reportable segments in the fourth quarter of 2006. The segment detail revised as a result of the new reportable business segments did not affect consolidated operating income for any year.

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. Such investments were $15 million and $32 million as of December 31, 2005 and 2006, respectively. 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, 2005	December 31, 2006
		(In millions)	
Natural gas distribution	30	$ 2,740	$ 2,875
Competitive natural gas sales and services	25	27	53
Interstate pipelines	53	1,520	1,943
Field services	52	367	429
Other property	13	20	36
Total		4,674	5,336
Accumulated depreciation and amortization:			
Natural gas distribution		(391)	(462)
Competitive natural gas sales and services		(5)	(9)
Interstate pipelines		(144)	(176)
Field services		(23)	(31)
Other property		(6)	(19)
Total accumulated depreciation and amortization		(569)	(697)
Property, plant and equipment, net		$ 4,105	$ 4,639

Goodwill by reportable business segment as of both December 31, 2005 and 2006 is as follows (in millions):

Natural Gas Distribution	$ 746
Interstate Pipelines	579
Competitive Natural Gas Sales and Services	339
Field Services	25
Other Operations	20
Total	$ 1,709

The Company performs its goodwill impairment test 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, 2006, 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.

(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 accounts of the utility operations of the Natural Gas Distribution business segment and to some of the accounts 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, 2005 and 2006:

	December 31, 2005	December 31, 2006
	(In millions)	
Regulatory assets in other long-term assets	$ 53	$ 50
Regulatory liabilities in other long-term liabilities	(434)	(456)
Total	$ (381)	$ (406)

If events were to occur that would make the recovery of these assets and liabilities no longer probable, the Company would be required to write-off or write-down these regulatory assets and liabilities.

The Company's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2005 and 2006, these removal costs of $406 million and $424 million, respectively, are classified as regulatory liabilities in the Consolidated Balance Sheets. A portion of the amount of removal costs that relates to asset retirement obligations has been reclassified from a regulatory liability to an asset retirement liability, which is included in other liabilities in the Consolidated Balance Sheets, in connection with the Company's adoption of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), effective December 31, 2005. At December 31, 2005 and 2006, the Company had recorded asset retirement obligations of $65 million and $66 million, respectively.

(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 2004, 2005 and 2006:

	Year Ended December 31, 2004	2005	2006
		(In millions)	
Depreciation expense	$ 171	$ 180	$ 181
Amortization expense	16	18	19
Total depreciation and amortization expense	$ 187	$ 198	$ 200

(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 through depreciation provisions 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 2004, 2005 and 2006, the Company capitalized interest and AFUDC of $2 million, $1 million and $6 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 2004, 2005 and 2006, the Company received allocations of CenterPoint Energy's tax benefits (expense) totaling $171 million, $171 million and ($3) million, respectively. The Company uses the liability method of accounting for deferred income taxes and measures deferred income taxes for all significant income tax temporary differences in accordance with SFAS No. 109, "Accounting for Income Taxes," (SFAS No. 109). Investment tax credits were deferred and are being amortized over the estimated lives of the related property. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy. Management evaluates uncertain tax positions and accrues for those which management believes are probable of an unfavorable outcome. For additional information regarding income taxes, see Note 7.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $38 million and $32 million at December 31, 2005 and 2006, respectively. The provision for doubtful accounts in the Company's Statements of Consolidated Income for 2004, 2005 and 2006 was $26 million, $37 million and $37 million, respectively.

As of December 31, 2005 and 2006, the Company had $141 million and $187 million of advances, respectively, under its receivables facility. CERC Corp. formed a bankruptcy remote subsidiary for the sole purpose of buying receivables created by the Company and selling those receivables to an unrelated third-party. Prior to October 2006, these transactions were accounted for as a sale of receivables under the provisions of SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," (SFAS No. 140) and, as a result, the related receivables were excluded from the Company's Consolidated Balance Sheets.

In October 2006, the Company amended its receivables facility and extended the termination date to October 30, 2007. The facility size was $250 million until December 2006, is $375 million from December 2006 to May 2007 and ranges from $150 million to $325 million during the period from May 2007 to the October 30, 2007 termination date of the facility. Under the terms of the amended receivables facility, the provisions for off-balance sheet sale accounting under SFAS No. 140 were no longer met. Accordingly, advances received upon the sale of receivables are accounted for as short-term borrowings as of December 31, 2006.

Funding under the receivables facility averaged $190 million, $166 million and $79 million in 2004, 2005 and 2006, respectively. Sales of receivables were approximately $2.4 billion, $2.0 billion and $555 million in 2004, 2005 and 2006, respectively.

(j) Inventory

Inventory consists principally of materials and supplies and natural gas. Material and supplies are valued at the lower of average cost or market. Natural gas inventories used in the retail natural gas distribution operations are also primarily valued at the lower of average cost or market. During 2006, the Company recorded $66 million in write-downs of natural gas inventory to the lower of average cost or market.

	December 31,	
	2005	2006
	(In millions)	
Materials and supplies	$ 29	$ 31
Natural gas	294	305
Total inventory	$ 323	$ 336

(k) Derivative Instruments

The Company utilizes derivative instruments such as physical forward contracts, swaps and options (energy derivatives) to mitigate the impact of changes in its natural gas business 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 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 as the hedged items. 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 financial instruments for trading purposes.

CenterPoint Energy has a Risk Oversight Committee composed of corporate and business segment officers that oversees all commodity price and credit risk activities, including the Company's trading, 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 trading of new products and commodities, monitor risk positions and ensure compliance with the CenterPoint Energy's risk management policies and procedures and trading 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, and 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 July 2006, the FASB issued FIN No. 48, "Accounting for Uncertainty in Income Taxes— An Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. The Company estimates the cumulative effect of adopting FIN 48 to be immaterial to the consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 establishes a framework for measuring fair value and requires expanded disclosure about the information used to measure fair value. The statement applies whenever other statements require or permit assets or liabilities to be measured at fair value. The statement does not expand the use of fair value accounting in any new circumstances and is effective for the Company for the year ended December 31, 2008 and for interim periods included in that year, with early adoption encouraged. The Company is evaluating the effect of adoption of this new standard on its financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – An Amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158). SFAS No. 158 requires the Company, as the sponsor of a plan, to (a) recognize on its Balance Sheets as an asset a plan's over-funded status or as a liability such plan's under-funded status, (b) measure a plan's assets and obligations as of the end of the Company's fiscal year and (c) recognize changes in the funded status of its plans in the year in which changes occur through adjustments to other comprehensive income. The Company adopted SFAS No. 158 as of December 31, 2006. The following table summarizes the effect of the adjustments to record the adoption of SFAS No. 158:

	Before Adoption of SFAS No. 158	Change due to SFAS No. 158	After Adoption of SFAS No. 158
Other Assets:			
Regulatory asset	$ —	$ 3	$ 3
Current Liabilities:			
Other	—	7	7
Other Liabilities:			
Accumulated deferred income taxes, net	—	(20)	(20)
Benefit obligations	89	18	107
Shareholders' Equity:			
Accumulated other comprehensive loss	—	(2)	(2)

Upon adoption of SFAS No. 158, the Company recorded a regulatory asset for its unrecognized costs associated with operations that have historically recovered and currently recover postretirement expenses in rates. The adoption of SFAS No. 158 did not impact the Company's compliance with debt covenants.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statements 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. The Company is evaluating the effect of adoption of this new standard on its financial position, results of operations and cash flows.

(o) Employee Benefit Plans

Pension Plans

Substantially all of the Company's employees participate in CenterPoint Energy's qualified non-contributory pension plan. Under the cash balance formula, participants accumulate a retirement benefit based upon 4% of eligible earnings and accrued interest. Prior to 1999, the pension plan accrued benefits based on years of service, final average pay and covered compensation. As a result, certain employees participating in the plan as of December 31, 1998 are eligible to receive the greater of the accrued benefit calculated under the prior plan 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 $35 million, $15 million and $16 million for the years ended December 31, 2004, 2005 and 2006, respectively.

In addition to the plan, the Company participates in CenterPoint Energy's non-qualified benefit restoration plan, which allows participants to retain the benefits to which they would have been entitled under the qualified pension plan except for federally mandated limits on these benefits or on the level of salary on which these 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, 2004, 2005 and 2006.

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 16% of compensation. CenterPoint Energy matches 75% of the first 6% of each employee's compensation contributed. CenterPoint Energy may contribute an additional discretionary match of up to 50% of the first 6% of each employee's compensation contributed. These 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 $16 million, $17 million and $17 million for the years ended December 31, 2004, 2005 and 2006, respectively.

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.

In January 2005, the Department of Health and Human Services' Centers for Medicare and Medicaid Services released final regulations governing the Medicare prescription drug benefit and other key elements of the Medicare Modernization Act. Under the final regulations, a greater portion of benefits offered under CenterPoint Energy's plans meets the definition of actuarial equivalence and therefore qualifies for federal subsidies equal to 28% of allowable drug costs. As a result, the Company has remeasured its obligations and costs to take into account the new regulations. The Medicare subsidy reduced net periodic postretirement benefit costs by approximately $5 million and $9 million for 2005 and 2006, respectively.

As of December 31, 2006, the Company adopted SFAS No. 158 for its postretirement benefits plans. For additional background relating to the accounting pronouncement and its impacts, see Note 2(n).

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,		
	2004	2005	2006
		(In millions)	
Service cost — benefits earned during the period	$ 2	$ 1	$ 1
Interest cost on projected benefit obligation	10	8	7
Expected return on plan assets	(2)	(2)	(1)
Amortization of prior service cost	2	2	2
Other	1	1	1
Net postretirement benefit cost	$ 13	$ 10	$ 10

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

	Year Ended December 31, 2004	2005	2006
Discount rate	6.25%	5.75%	5.70%
Expected return on plan assets	8.5%	8.0%	4.8%

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 2005 and 2006. The measurement dates for plan assets and obligations were December 31, 2005 and 2006.

	Year Ended December 31, 2005	2006
	(In millions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 174	$ 132
Service cost	1	1
Interest cost	8	7
Benefit enhancement	1	1
Benefits paid	(17)	(22)
Plan amendment	—	8
Medicare reimbursement	—	3
Participant contributions	3	4
Actuarial loss	(38)	—
Accumulated benefit obligation, end of year	$ 132	$ 134
Change in Plan Assets		
Plan assets, beginning of year	$ 21	$ 20
Benefits paid	(17)	(22)
Employer contributions	12	16
Participant contributions	3	4
Actual investment return	1	2
Plan assets, end of year	$ 20	$ 20
Reconciliation of Funded Status		
Funded status	$ (112)	$ (114)
Unrecognized prior service cost	11	—
Unrecognized actuarial loss	9	—
Net amount recognized in balance sheets	$ (92)	$ (114)
Actuarial Assumptions		
Discount rate	5.70%	5.85%
Expected long-term return on assets	4.80%	4.50%
Healthcare cost trend rate assumed for the next year	9.00%	7.00%
Prescription cost trend rate assumed for the next year	—	13.00%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.50%	5.50%
Year that the rate reaches the ultimate trend rate	2011	2014

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

	Year Ended December 31, 2005	2006
	(In millions)	
Unrecognized actuarial loss	$ —	$ 8
Unrecognized prior service cost	—	14
Net amount recognized in other comprehensive income	$ —	$ 22

The amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost during 2007 are as follows:

	Postretirement Benefits (In millions)
Unrecognized prior service cost	$ 2
Amounts in comprehensive income to be recognized as net periodic cost in 2007	$ 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	$ 7	$ 6
Effect on the total of service and interest cost	—	—

The following table displays the weighted average asset allocations as of December 31, 2005 and 2006 for the Company's postretirement benefit plan:

	December 31, 2005	December 31, 2006
Domestic equity securities	8%	6%
Debt securities	90	93
Cash	2	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, which 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 expected rate of return assumption was developed by reviewing the targeted asset allocations and historical index performance of the applicable asset classes over a 15-year period, adjusted for investment fees and diversification effects.

The Company expects to contribute $19 million to its postretirement benefits plan in 2007.

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

	Postretirement Benefit Plan	
	Benefit Payments	Medicare Subsidy Receipts
2007	$11	$(2)
2008	11	(1)
2009	11	(1)
2010	12	(2)
2011	13	(2)
2012-2016	66	(9)

Postemployment Benefits

The Company participates in CenterPoint Energy's plan which 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). Postemployment benefits costs were $3 million each year in 2004, 2005 and 2006, respectively.

Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31 ,2005 and 2006, was $19 million and $20 million, respectively, related to postemployment benefits.

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 2004, 2005 and 2006, the benefits expense relating to these programs was less than $1 million each year. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2005 and 2006, was $7 million and $5 million, respectively, relating to deferred compensation plans.

(p) Other Current Assets and Liabilities

Included in other current assets on the Consolidated Balance Sheets at December 31, 2005 and 2006 was $34 million and $113 million, respectively, of margin deposits and $-0- and $110 million, respectively of under recovered gas cost. Included in other current liabilities on the Consolidated Balance Sheets at December 31, 2005 and 2006 was $38 million and $123 million, respectively, of over recovered gas cost.

3. Regulatory Matters

(a) Rate Cases

Arkansas. In January 2007, CERC Corp.'s natural gas distribution business (Gas Operations) filed an application with the Arkansas Public Service Commission (APSC) to change its natural gas distribution rates. This filing seeks approval to change the base rate portion of a customer's natural gas bill, which makes up about 30 percent of the total bill and covers the cost of distributing natural gas. The filing does not apply to the Gas Supply Rate (GSR), which makes up the remaining approximately 70 percent of the bill. Through the GSR, Gas Operations passes through to its customers the actual cost it pays for the natural gas it purchases for use by its customers without any mark-up. In a separate filing in January 2007, Gas Operations reduced the GSR by approximately 9 percent. The APSC approved this GSR filing in January 2007.

The filing seeks approval by the APSC of the new rates that would go into effect later this year and would generate approximately $51 million in additional revenue on an annual basis. The effect on individual monthly bills would vary depending on natural gas use and customer class. As part of the base rate filing, Gas Operations is also proposing a mechanism that, if approved, would help stabilize revenues, eliminate the potential conflict between its efforts to earn a reasonable return on invested capital while promoting energy efficiency initiatives, and minimize the need for future rate cases. As part of the revenue stabilization mechanism, the Company proposed to reduce the requested return on equity by 35 basis points which would reduce the base rate increase by $1 million. The mechanism would be in place through December 31, 2010.

In Arkansas, the APSC in December 2006 adopted rules governing affiliate transactions involving public utilities operating in Arkansas. The rules treat as affiliate transactions all transactions between the Company's Arkansas utility operations and other divisions of the Company, as well as transactions between the Arkansas utility operations and affiliates of the Company. All such affiliate transactions are required to be priced under an asymmetrical pricing formula under which the Arkansas utility operations would benefit from any difference between the cost of providing goods and services to or from the Arkansas utility operations and the market value of those goods or services. Additionally, the Arkansas utility operations are not permitted to participate in any financing other than to finance retail utility operations in Arkansas, which would preclude continuation of existing financing arrangements in which the Company finances its divisions and subsidiaries, including its Arkansas utility operations.

Although the Arkansas rules are now in effect, the Company and other gas and electric utilities operating in Arkansas sought reconsideration of the rules by the APSC. In February 2007, the APSC granted that reconsideration and suspended operation of the rules in order to permit time for additional consideration. If the rules are not significantly modified on reconsideration, the Company would be entitled to seek judicial review. In adopting the rules, the APSC indicated that affiliate transactions and financial arrangements currently in effect will be deemed in compliance until December 19, 2007, and that utilities may seek waivers of specific provisions of the rules. If the rules ultimately become effective as presently adopted, the Company would need to seek waivers from certain provisions of the rules or would be required to make significant modifications to existing practices, which could include the formation of and transfer of assets to subsidiaries.

If this regulatory framework becomes effective, it could have adverse impacts on the Company's ability to operate and provide cost-effective utility service.

Texas. In September 2006, Gas Operations filed Statements of Intent (SOI) with 47 cities in its Texas coast service territory to increase miscellaneous service charges and to allow recovery of the costs of financial hedging transactions through its purchased gas cost adjustment. In November 2006, these changes became effective as all 47 cities either approved the filings or took no action, thereby allowing rates to go into effect by operation of law. In December 2006, Gas Operations filed a SOI with the Railroad Commission seeking to implement such changes in the environs of the Texas coast service territory. Gas Operations' filing has been suspended to allow for discovery and pre-hearing conferences, and a final determination is expected in the second quarter of 2007.

Minnesota. At September 30, 2006, Gas Operations had recorded approximately $45 million as a regulatory asset related to prior years' unrecovered purchased gas costs in its Minnesota service territory. Of the total, approximately $24 million related to the period from July 1, 2004 through June 30, 2006, and approximately $21 million related to the period from July 1, 2000 through June 30, 2004. The amounts related to periods prior to July 1, 2004 arose as a result of revisions to the calculation of unrecovered purchased gas costs previously approved by the Minnesota Public Utilities Commission (MPUC). Recovery of this regulatory asset was dependent upon obtaining a waiver from the MPUC rules. In November 2006, the MPUC considered the request for variance and voted to deny the waiver. Accordingly, the Company recorded a $21 million adjustment to reduce pre-tax earnings in the fourth quarter of 2006 and reduced the regulatory asset by an equal amount. In February 2007, the MPUC denied reconsideration. Although no prediction can be made as to the ultimate outcome of this matter, the Company expects to appeal the MPUC's decision which precludes recovery of the cost of this gas, which was delivered to its customers and for which the Company has never been paid.

In November 2005, the Company filed a request with the MPUC to increase annual rates by approximately $41 million. In December 2005, the MPUC approved an interim rate increase of approximately $35 million that was implemented January 1, 2006. Any excess of amounts collected under the interim rates over the amounts approved in final rates is subject to refund to customers. In October 2006, the MPUC considered the request and indicated that it could grant a rate increase of approximately $21 million. In addition, the MPUC approved a $5 million affordability program to assist low-income customers, the actual cost of which will be recovered in rates in addition to the $21 million rate increase. Although the Minnesota Attorney General's Office (OAG) requested reconsideration of certain parts of the MPUC's decision, in January 2007, the MPUC voted to deny reconsideration and a final order was issued in January 2007. The proportional share of the excess of the amounts collected in interim rates over the amount allowed by the final order will be refunded to customers after implementation of final rates. As of December 31, 2006, approximately $12 million has been accrued for the refund and was recorded as a reduction of revenues through the establishment of a regulatory liability.

In December 2004, the MPUC opened an investigation to determine whether Gas Operations' practices regarding restoring natural gas service during the period between October 15 and April 15 (Cold Weather Period) were in compliance with the MPUC's Cold Weather Rule (CWR), which governs disconnection and reconnection of customers during the Cold Weather Period. In June 2005, the OAG issued its report alleging the Company had violated the CWR and recommended a $5 million penalty. In addition, in June 2005, the Company was named in a suit filed in the United States District Court, District of Minnesota on behalf of a purported class of customers who allege that its conduct under the CWR was in violation of the law. In August 2006, the court gave final approval to a $13.5 million settlement which resolved all but one small claim against the Company which have or could have been asserted by residential natural gas customers in the CWR class action. The agreement was also approved by the MPUC, resolving the claims made by the OAG. The anticipated costs of this settlement were accrued during the fourth quarter of 2005.

(b) City of Tyler, Texas Dispute

In July 2002, the City of Tyler, Texas, asserted that Gas Operations had overcharged residential and small commercial customers in that city for gas costs under supply agreements in effect since 1992. That dispute was referred to the Railroad Commission of Texas (Railroad Commission) by agreement of the parties for a determination of whether Gas Operations has properly charged and collected for gas service to its residential and commercial customers in its Tyler distribution system in accordance with lawful filed tariffs during the period beginning November 1, 1992, and ending October 31, 2002. In May 2005, the Railroad Commission issued a final order finding that Gas Operations had complied with its tariffs, acted prudently in entering into its gas supply contracts, and prudently managed those contracts. The City of Tyler appealed this order to a Travis County District Court, but in April 2006, Gas Operations and the City of Tyler reached a settlement regarding the rates in the City of Tyler and other aspects of the dispute between them. As contemplated by that settlement, the City of Tyler's appeal to the district court was dismissed on July 31, 2006, and the Railroad Commission's final order and findings are no longer subject to further review or modification.

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's money pool borrowings of $186 million at December 31, 2006 had a weighted average interest rate of 5.37%.

For the years ended December 31, 2004, 2005 and 2006, the Company had net interest income (expense) related to affiliate borrowings of $9 million, $3 million and $(2) 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 $116 million, $129 million and $133 million for 2004, 2005 and 2006, 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 benefits (expense) of $171 million, $171 million and ($3) million for 2004, 2005 and 2006, respectively, which was recorded in additional paid-in capital.

In 2004, 2005 and 2006, the Company paid dividends of $13 million, $100 million and $100 million, respectively.

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 (energy derivatives) to mitigate the impact of changes in its natural gas businesses on its operating results and cash flows.

(a) Non-Trading Activities

Cash Flow Hedges. The Company enters 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 its wholesale and retail customer obligations. During the years ended December 31, 2004, 2005 and 2006, hedge ineffectiveness resulted in a loss of less than $1 million, a loss of $2 million and a gain of $2 million, respectively, 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 will not occur, the Company realizes in net income the deferred gains and losses previously recognized in accumulated other comprehensive loss. Once the anticipated transaction affects earnings, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in the Company's 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 Condensed Statements of Consolidated Cash Flows in the same category as the item being hedged. As of December 31, 2006, the Company expects $42 million ($26 million after-tax) in accumulated other comprehensive income to be reclassified as a decrease in Natural gas expense during the next twelve months.

The maximum length of time the Company is hedging its exposure to the variability in future cash flows using financial instruments is primarily two years with a limited amount up to four years. 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. While the Company utilizes these financial instruments to manage physical commodity price risks, it does not engage in proprietary or speculative commodity trading. During the years ended December 31, 2004, 2005 and 2006, the Company recognized unrealized net gains of $2 million, $2 million and $34 million, respectively. These derivative gains are included in the Statements of Consolidated Income under the "Expenses" caption "Natural gas."

(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, 2005 and 2006 (in millions):

	December 31, 2005		December 31, 2006	
	Investment Grade(1)	Total	Investment Grade(1)	Total
Energy marketers	$ 24	$ 25	$ 22	$ 27
Financial institutions	208	208	51	51
Other	—	2	41	41
Total	$ 232	$ 235	$ 114	$ 119

(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.

6. Short-term Borrowings and Long-term Debt

	December 31, 2005		December 31, 2006	
	Long-Term	Current(1)	Long-Term	Current(1)
	(In millions)			
Short-term borrowings:				
CERC Corp. receivables facility	$ —	$ —	$ —	$ 187
Long-term debt:				
Convertible subordinated debentures 6.00% due 2012	63	6	56	7
Senior notes 5.95% to 7.875% due 2007 to 2016	1,772	148	2,097	—
Unamortized discount and premium(2)	3	—	2	—
Total long-term debt	1,838	154	2,155	7
Total debt	$ 1,838	$ 154	$ 2,155	$ 194

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

(2) 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 $5 million and $4 million at December 31, 2005 and 2006, respectively, which is being amortized over the respective remaining term of the related long-term debt.

(a) Short-term Borrowings

In October 2006, the Company amended its receivables facility and extended the termination date to October 30, 2007. The facility size was $250 million until December 2006, is $375 million from December 2006 to May 2007 and ranges from $150 million to $325 million during the period from May 2007 to the October 30, 2007 termination date. Under the terms of the amended receivables facility, the provisions for sale accounting under SFAS No. 140 were no longer met. Accordingly, advances received by the Company upon the sale of receivables are accounted for as short-term borrowings as of December 31, 2006. As of December 31, 2006, $187 million was advanced for the purchase of receivables under the Company's receivables facility. As of December 31, 2006, advances had an interest rate of 5.60%.

(b) Long-term Debt

Senior Notes. In May 2006, the Company issued $325 million aggregate principal amount of senior notes due in May 2016 with an interest rate of 6.15%. The proceeds from the sale of the senior notes were used for general corporate purposes, including repayment or refinancing of debt (including $145 million of the Company's 8.90% debentures repaid December 15, 2006), capital expenditures and working capital. For a discussion of the Company's debt transactions in 2007, see Note 12.

Revolving Credit Facilities. In March 2006, the Company replaced its $400 million five-year revolving credit facility with a $550 million five-year revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 45 basis points based on the Company's current credit ratings, as compared to LIBOR plus 55 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt to total capitalization covenant of 65%.

Under the credit facility, an additional utilization fee of 10 basis points applies to borrowings any time more than 50% of the facility is utilized, and the spread to LIBOR fluctuates based on the borrower's credit rating. Borrowings under each of the facilities are subject to customary terms and conditions. However, there is no requirement that the Company make representations prior to borrowings as to the absence of material adverse changes or litigation that could be expected to have a material adverse effect. Borrowings under each of the credit facilities are subject to acceleration upon the occurrence of events of default that the Company considers customary.

As of December 31, 2006, the Company had no borrowings and approximately $4 million of outstanding letters of credit under its $550 million credit facility. Additionally, the Company was in compliance with all covenants as of December 31, 2006.

Maturities. The Company's consolidated maturities of long-term debt and sinking fund requirements are $7 million in 2007, $307 million in 2008, $6 million in 2009 and $6 million in 2010 and $557 million in 2011.

7. Income Taxes

The Company's current and deferred components of income tax expense are as follows:

	Year Ended December 31,		
	2004	2005	2006
		(In millions)	
Current			
Federal	$ 86	$ 82	$ 97
State	10	2	36
Total current	96	84	133
Deferred			
Federal	(3)	1	(22)
State	(6)	31	5
Total deferred	(9)	32	(17)
Income tax expense	$ 87	$ 116	$ 116

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

	Year Ended December 31,		
	2004	2005	2006
		(In millions)	
Income before income taxes	$ 231	$ 309	$ 323
Federal statutory rate	35%	35%	35%
Income tax expense at statutory rate	81	108	113
Increase (decrease) in tax resulting from:			
State income taxes, net of valuation allowances and federal income tax benefit	2	22	27
Tax reserves	—	(13)	(20)
Deferred tax asset write-off	4	—	—
Other, net	—	(1)	(4)
Total	6	8	3
Income tax expense	$ 87	$ 116	$ 116
Effective Rate	37.5%	37.4%	36.1%

Following are the Company’s tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases:

	December 31, 2005	December 31, 2006
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 19	$ 16
Total current deferred tax assets	19	16
Non-current:		
Employee benefits	73	78
Operating and capital loss carryforwards	26	27
Deferred gas costs	59	58
Other	80	48
Total non-current deferred tax assets before valuation allowance	238	211
Valuation allowance	(21)	(22)
Total non-current deferred tax assets	217	189
Total deferred tax assets	236	205
Deferred tax liabilities:		
Current:		
Non-trading derivative liabilities, net	2	14
Total current deferred tax liabilities	2	14
Non-current:		
Depreciation	821	822
Regulatory liability	36	13
Other	23	16
Total non-current deferred tax liabilities	880	851
Total deferred tax liabilities	882	865
Accumulated deferred income taxes, net	$ 646	$ 660

The Company is included in the consolidated income tax returns of CenterPoint Energy. CenterPoint Energy’s consolidated federal income tax returns have been audited and settled through the 1996 tax year. The 1997 through 2003 consolidated federal income tax returns are currently under audit.

Tax Attribute Carryforwards. Based on returns filed, the Company has approximately $257 million of state net operating loss carryforwards. The losses are available to offset future state taxable income through the year 2026. Substantially all of the state loss carryforwards will expire between 2010 and 2021. A valuation allowance has been established against approximately $111 million of the state net operating loss carryforwards.

Tax Contingencies. The Company reached tentative settlements with the Internal Revenue Service for a number of tax matters in the fourth quarter of 2006; including issues associated with prior acquisitions and dispositions. Those tentative settlements have allowed the Company to reduce its total tax and related interest reserve from $32 million at December 31, 2005 to $12 million at December 31, 2006. Most of the remaining reserve is related to certain tax positions taken with respect to state tax filings.

8. Commitments and Contingencies

Natural gas supply commitments include natural gas contracts related to the Company’s natural gas distribution and competitive natural gas sales and services operations, 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, 2005 and 2006 as these contracts meet the SFAS No. 133 exemption to be classified as normal purchases contracts. Natural gas supply commitments also include natural gas transportation and storage contracts that do not meet the definition of a derivative. As of December 31, 2006, minimum payment obligations for natural gas supply commitments are approximately $922 million in 2007, $294 million in 2008, $210 million in 2009, $207 million in 2010 and $1.4 billion in 2011 and thereafter.

(b) Lease Commitments

The following table sets forth information concerning the Company's obligations under non-cancelable long-term operating leases, principally consisting of rental agreements for building space, data processing equipment and vehicles, including major work equipment (in millions):

2007	$ 16
2008	14
2009	11
2010	8
2011	6
2012 and beyond	14
Total	$ 69

Total rental expense for all operating leases was $30 million, $32 million and $51 million in 2004, 2005 and 2006, respectively.

(c) Capital Commitments

Carthage to Perryville. In October 2005, CenterPoint Energy Gas Transmission Company (CEGT) signed a 10-year firm transportation agreement with XTO Energy (XTO) to transport 600 million cubic feet (MMcf) per day of natural gas from Carthage, Texas to CEGT's Perryville hub in Northeast Louisiana. To accommodate this transaction, CEGT filed a certificate application with the Federal Energy Regulatory Commission (FERC) in March 2006 to build a 172-mile, 42-inch diameter pipeline and related compression facilities. The capacity of the pipeline under this filing will be 1.25 billion cubic feet (Bcf) per day. CEGT has signed firm contracts for the full capacity of the pipeline.

In October 2006, the FERC issued CEGT's certificate to construct, own and operate the pipeline and compression facilities. CEGT has begun construction of the facilities and expects to place the facilities in service in the second quarter of 2007 at a cost of approximately $500 million.

Based on interest expressed during an open season held in 2006, and subject to FERC approval, CEGT may expand capacity of the pipeline to 1.5 Bcf per day, which would bring the total estimated capital cost of the project to approximately $550 million. In September 2006, CEGT filed for approval to increase the maximum allowable operating pressure with the U.S. Department of Transportation. In December 2006, CEGT filed for the necessary certificate to expand capacity of the pipeline with the FERC. CEGT expects to receive the approvals in the third quarter of 2007.

During the four-year period subsequent to the in-service date of the pipeline, XTO can request, and subject to mutual negotiations that meet specific financial parameters and to FERC approval, CEGT would construct a 67-mile extension from CEGT's Perryville hub to an interconnect with Texas Eastern Gas Transmission at Union Church, Mississippi.

Southeast Supply Header. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., a wholly owned subsidiary, and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture (Southeast Supply Header or SESH) to construct, own and operate a 270-mile pipeline that will extend from CEGT's Perryville hub in northeast Louisiana to Gulfstream Natural Gas System, which is 50 percent owned by an affiliate of Spectra. In August 2006, the joint venture signed an agreement with Florida Power & Light Company (FPL) for firm transportation services, which subscribed approximately half of the planned 1 Bcf per day capacity of the pipeline. FPL's commitment was contingent on the approval of the FPL contract by the Florida Public Service Commission, which was received in December 2006. Subject to the joint venture receiving a certificate from the FERC to construct, own and operate the pipeline, subsidiaries of Spectra and the Company have committed to build the pipeline. In December 2006, the joint venture signed agreements with affiliates of Progress Energy Florida, Southern Company, Tampa Electric Company, and EOG Resources, Inc. bringing the total subscribed capacity to 945 MMcf per day. Additionally, SESH and Southern Natural Gas (SNG) have executed a definitive agreement that provides for SNG to jointly own the first 115 miles of the pipeline. Under the agreement, SNG will own an undivided interest in the portion of the pipeline from Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter will be increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that could increase the capacity up to 500 MMcf per day. An application to construct, own and operate the pipeline was filed with the FERC in December 2006. Subject to receipt of FERC authorization and construction in accordance with planned schedule, the Company expects an in-service date in the summer of 2008. The total cost of the combined project is estimated to be $800 to $900 million with SESH's net costs of $700 to $800 million after SNG's contribution.

(d) Legal, Environmental and Other Matters

Legal Matters

Natural Gas Measurement Lawsuits. CERC Corp. and certain of its subsidiaries are defendants in a lawsuit filed in 1997 under the Federal False Claims Act alleging mismeasurement of natural gas produced from federal and Indian lands. The suit seeks undisclosed damages, along with statutory penalties, interest, costs and fees. The complaint is part of a larger series of complaints filed against 77 natural gas pipelines and their subsidiaries and affiliates. An earlier single action making substantially similar allegations against the pipelines was dismissed by the federal district court for the District of Columbia on grounds of improper joinder and lack of jurisdiction. As a result, the various individual complaints were filed in numerous courts throughout the country. This case has been consolidated, together with the other similar False Claims Act cases, in the federal district court in Cheyenne, Wyoming. On October 20, 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, but the plaintiff has sought review of that dismissal from the Court of Appeals for the 10th Circuit.

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 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 suit was filed in state district court in Wharton County, Texas against the Company, CenterPoint Energy, Entex Gas Marketing Company, 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. Subsequently, the plaintiffs added as defendants CenterPoint Energy Marketing Inc., CEGT, United Gas, Inc., Louisiana Unit Gas Transmission Company, CenterPoint Energy Pipeline Services, Inc., and CenterPoint Energy Trading and Transportation Group, Inc., all of which are subsidiaries of the Company. The plaintiffs alleged that defendants inflated the prices charged to certain consumers of natural gas. In February 2003, a similar 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). In October 2004, a similar case was filed in district court in Miller County, Arkansas against the Company, CenterPoint Energy, Entex Gas Marketing Company, CEGT, CenterPoint Energy Field Services, CenterPoint Energy Pipeline Services, Inc., Mississippi River Transmission Corp. (MRT) and other non-affiliated companies alleging fraud, unjust enrichment and civil conspiracy with respect to rates charged to certain consumers of natural gas in at least the states of Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Subsequently, the plaintiffs dropped as defendants CEGT and MRT. 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 cases have been stayed pending the resolution of the respective proceedings by the LPSC. The plaintiffs in the Miller County case seek class certification, but the proposed class has not been certified. In February 2005, the Wharton County case was removed to federal district court in Houston, Texas, and in March 2005, the plaintiffs voluntarily moved to dismiss the case and agreed not to refile the claims asserted unless the Miller County case is not certified as a class action or is later decertified. The range of relief sought by the plaintiffs in these cases includes injunctive and declaratory relief, restitution for the alleged overcharges, exemplary damages or trebling of actual damages, civil penalties and attorney's fees. In these cases, the Company, CenterPoint Energy and their affiliates deny that they have overcharged any of their customers for natural gas and believe that the amounts recovered for purchased gas have been in accordance with what is permitted by state and municipal regulatory authorities. The allegations in these cases are similar to those asserted in the City of Tyler proceeding, as described in Note 3(b). The Company does not expect the outcome of these matters to have a material impact on its financial condition, results of operations or cash flows.

Storage Facility Litigation. In February 2007, an Oklahoma district court in Coal Creek 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 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 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 which 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.

Pipeline Safety Compliance. Pursuant to an order from the Minnesota Office of Pipeline Safety, CERC substantially completed removal of certain non-code-compliant components from a portion of its distribution system by December 2, 2005. The components were installed by a predecessor company, which was not affiliated with the Company during the period in which the components were installed. In November 2005, the Company filed a request with the MPUC to recover the capitalized expenditures (approximately $39 million) and related expenses, together with a return on the capitalized portion through rates as part of its then existing rate case as further discussed in Note 3(a). As part of its final rate order, the MPUC allowed capitalized expenditures, plus approximately $2 million previously expensed in 2005, in rate base. Return on approximately $4 million of the $41 million is limited to the cost of long-term debt included in the cost of capital pending the outcome of litigation against the predecessor companies that installed the original service lines.

Minnesota Cold Weather Rule. For a discussion of this matter, see Note 3(a) above.

Environmental Matters

Hydrocarbon Contamination. CERC Corp. and certain of its subsidiaries are among the defendants in lawsuits filed beginning in August 2001 in Caddo Parish and Bossier Parish, Louisiana. The suits allege that, at some unspecified date prior to 1985, the defendants allowed or caused hydrocarbon or chemical contamination of the Wilcox Aquifer, which lies beneath property owned or leased by certain of the defendants and which is the sole or primary drinking water aquifer in the area. The primary source of the contamination is alleged by the plaintiffs to be a gas processing facility in Haughton, Bossier Parish, Louisiana known as the “Sligo Facility,” which was formerly operated by a predecessor in interest of CERC Corp. This facility was purportedly used for gathering natural gas from surrounding wells, separating liquid hydrocarbons from the natural gas for marketing, and transmission of natural gas for distribution.

Beginning about 1985, the predecessors of certain CERC Corp. defendants engaged in a voluntary remediation of any subsurface contamination of the groundwater below the property they owned or leased. This work has been done in conjunction with and under the direction of the Louisiana Department of Environmental Quality. The plaintiffs seek monetary damages for alleged damage to the aquifer underlying their property, including the cost of restoring their property to its original condition and damages for diminution of value of their property. In addition, plaintiffs seek damages for trespass, punitive, and exemplary damages. The parties have reached an agreement on terms of a settlement in principle of this matter. That settlement would require approval from the Louisiana Department of Environmental Quality of an acceptable remediation plan that could be implemented by the Company. The Company currently is seeking that approval. If the currently agreed terms for settlement are ultimately implemented, the Company does not expect the ultimate cost associated with resolving this matter to have a material impact on the financial condition, results of operations or cash flows of the Company.

Manufactured Gas Plant Sites. The Company and its predecessors operated manufactured gas plants (MGP) 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, 2006, the Company had accrued $14 million for remediation of these Minnesota sites. At December 31, 2006, 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, 2006, 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 two lawsuits, one filed in the United States District Court, District of Maine and the other filed in the Middle District of Florida, Jacksonville Division, 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 one of the lawsuits. In March 2005, the federal district court considering the suit for contribution in Florida granted the Company’s motion to dismiss on the grounds that the Company was not an “operator” of the site as had been alleged. In October 2006, the 11th Circuit Court of Appeals affirmed the district court’s dismissal. In June 2006, the federal district court in Maine that is considering the other suit 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 these sites and the range of environmental expenditures for potential remediation. However, the Company believes it is not liable as a former owner or operator of those sites under the Comprehensive Environmental, Response, Compensation and Liability Act of 1980, as amended, and applicable state statutes, and is vigorously contesting those suits 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.

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 and CenterPoint Energy against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the benefit of the Company and CenterPoint Energy, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. The Company currently holds letters of credit in the amount of $33.3 million issued on behalf of RRI against guaranties that have not been released. CenterPoint Energy's current exposure under the guaranties relates to the Company's guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. RRI continues to meet its obligations under the transportation contracts, and the Company believes current market conditions make those contracts valuable for transportation services in the near term. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, the Company's exposure to the counterparty under the guaranty could exceed the security provided by RRI. CenterPoint Energy has requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of the Company's obligations under the guaranty. In June 2006, the RRI trading subsidiary and the Company jointly filed a complaint at the FERC against the counterparty on the Company's guaranty. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security demanded by the counterparty exceeds the level permitted by the FERC's policies. The complaint asks the FERC to require the counterparty to release the Company from its guaranty obligation and, in its place, accept (i) a guaranty from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit limited to (A) one year of demand charges for a transportation agreement related to a 2003 expansion of the counterparty's pipeline, and (B) three months of demand charges for three other transportation agreements held by the RRI trading subsidiary. The counterparty has argued that the amount of the guaranty does not violate the FERC's policies and that the proposed substitution of credit support is not authorized under the counterparty's financing documents or required by FERC's policy. The parties have now completed their submissions to FERC regarding the complaint. The Company cannot predict what action the FERC may take on the complaint or when the FERC may rule. In addition to the FERC proceeding, in February 2007 the Company and CenterPoint Energy made a formal demand on RRI under procedures provided for by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy and RRI. That demand seeks to resolve the disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. It is possible that this demand could lead to an arbitration proceeding between the companies, but when and on what terms the disagreement with RRI will ultimately be resolved cannot be predicted.

9. 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, 2005 and 2006 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, 2005		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Financial liabilities:				
Long-term debt	$1,992	$2,182	$2,162	$2,311

10. Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2005			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions)			
Revenues	$2,248	$1,426	$1,587	$2,809
Operating income	202	69	40	153
Net income	96	27	4	66

	Year Ended December 31, 2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions)			
Revenues	$2,690	$1,384	$1,400	$2,054
Operating income	200	65	69	138
Net income	97	23	13	74

11. 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 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. Beginning in the fourth quarter of 2006, the Company is reporting its interstate pipelines and field services businesses as two separate business segments, the Interstate Pipelines business segment and the Field Services business segment. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. The Interstate Pipelines 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. All prior periods have been recast to conform to the 2006 presentation.

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:

	Revenues from External Customers	Intersegment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2004:						
Natural Gas Distribution	$3,577	$ 2	$141	$178	$ 4,083	$196
Competitive Natural Gas Sales and Services	2,593	255	2	44	964	1
Interstate Pipelines	239	129	36	129	2,164	39
Field Services	67	25	8	51	451	34
Other	(4)	5	—	(9)	792	(1)
Reconciling Eliminations	—	(416)	—	—	(987)	—
Consolidated	$6,472	$ —	$187	$393	$ 7,467	$269
As of and for the year ended December 31, 2005:						
Natural Gas Distribution	$3,837	$ 9	$152	$175	$ 4,612	$249
Competitive Natural Gas Sales and Services	3,884	245	2	60	1,849	12
Interstate Pipelines	255	131	36	165	2,400	118
Field Services	91	29	9	70	529	38
Other	3	7	(1)	(6)	743	—
Reconciling Eliminations	—	(421)	—	—	(1,832)	—
Consolidated	$8,070	$ —	$198	$464	$ 8,301	$417
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	255	133	37	181	2,738	437
Field Services	119	31	10	89	608	65
Other	—	5	—	1	1,086	—
Reconciling Eliminations	—	(259)	—	—	(1,581)	—
Consolidated	$7,528	$ —	$200	$472	$ 8,815	$707

	Year Ended December 31,		
	2004	2005	2006
		(In millions)	
Revenues by Products and Services:			
Retail gas sales	$ 4,239	$ 4,871	$ 4,546
Wholesale gas sales	1,526	2,410	2,331
Gas transport	613	684	550
Energy products and services	94	105	101
Total	$ 6,472	$ 8,070	$ 7,528

12. Subsequent Event

In February 2007, the Company issued $150 million aggregate principal amount of senior notes due in February 2037 with an interest rate of 6.25%. The proceeds from the sale of the senior notes were used to repay advances for the purchase of receivables under the Company's $375 million receivables facility. Such repayment provides increased liquidity and capital resources for general corporate purposes.

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

None.

Item 9A. ***Controls and Procedures.***

Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2006 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, 2006 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 Accountant Fees and Services*

Aggregate fees billed to the Company during the fiscal years ending December 31, 2005 and 2006 by its principal accounting firm, Deloitte & Touche LLP, are set forth below. These fees do not include certain fees related to general corporate matters, financial reporting, tax and other fees which have not been allocated to the Company by CenterPoint Energy.

	Year Ended December 31, 2005	Year Ended December 31, 2006
Audit fees	$ 967,192	$ 1,108,600
Audit-related fees	107,050	178,500
Total audit and audit-related fees	1,074,242	1,287,100
Tax fees	—	—
All other fees	—	—
Total fees	$ 1,074,242	$ 1,287,100

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, 2006.

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 70.

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) as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated March 9, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company's adoption of a new accounting standard for conditional asset retirement obligations in 2005); 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 9, 2007

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, 2006

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, 2006:					
Accumulated provisions:					
Uncollectible accounts receivable	$38	$ 37	$—	$43	$32
Deferred tax asset valuation allowance	21	1	—	—	22
Year Ended December 31, 2005:					
Accumulated provisions:					
Uncollectible accounts receivable	28	37	—	27	38
Deferred tax asset valuation allowance	20	1	—	—	21
Year Ended December 31, 2004:					
Accumulated provisions:					
Uncollectible accounts receivable	28	26	—	26	28
Deferred tax asset valuation allowance	73	(67)	14	—	20

(1) Charges to other accounts represent changes in presentation to reflect state tax attributes net of federal tax benefit as well as to reflect amounts that were netted against related attribute balances in prior years.

(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.

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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 9th day of March, 2007.

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 9, 2007.

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/ JAMES S. BRIAN (James S. Brian)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)

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CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2005

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, HL&P, HI Merger, Inc. and NorAm dated August 11, 1996	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 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	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, 2006	1-31447	4(f)(11)
4(c)	— $550,000,000 Amended and Restated Credit Agreement, dated as of March 31, 2006, among CERC Corp., as Borrower, and the banks named therein	CNP's Form 8-K dated March 31, 2006	1-31447	4.3

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,				
	2002	2003	2004	2005	2006
Net income	$ 120	$ 129	$ 144	$ 193	$ 206
Income taxes	88	59	87	116	117
Capitalized interest	(1)	(1)	(2)	(1)	(6)
	207	187	229	308	317
Fixed charges, as defined:					
Interest expense	154	179	178	176	167
Capitalized interest	1	1	2	1	6
Interest component of rentals charged to operating expense	10	9	10	11	17
Total fixed charges	165	189	190	188	190
Earnings, as defined	$ 372	$ 376	$ 419	$ 496	$ 507
Ratio of earnings to fixed charges	2.25	1.99	2.20	2.64	2.67

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-136965 on Form S-3 of our reports dated March 9, 2007, relating to i) the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of a new accounting standard related to conditional asset retirement obligations in 2005), and ii) the consolidated financial statement schedule, appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2006.

DELOITTE & TOUCHE LLP

Houston, Texas

March 9, 2007

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)) 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) 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

(c) 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 9, 2007

/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)) 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) 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

(c) 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 9, 2007

/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, 2006 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, David M. McClanahan, 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 9, 2007

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, 2006 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Gary L. Whitlock, 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 9, 2007