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

FORM 10-K

(MARK ONE)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2005

OR

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

FOR THE TRANSITION PERIOD FROM ________________ TO ________________

COMMISSION FILE NUMBER 1-13265

CENTERPOINT ENERGY RESOURCES CORP.
(Exact name of registrant as specified in its charter)

DELAWARE (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 [ ] No [X]

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

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 [X] No [ ]

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

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 [ ] Accelerated filer [ ] Non-accelerated filer [X]

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

The aggregate market value of the common equity held by non-affiliates as of June 30, 2005: 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 and Executive Officers of the Registrant), 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) 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 2003, 2004 and 2005.

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 gas distribution systems serving approximately 3.1 million customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. Through wholly owned subsidiaries, we also own two interstate natural gas pipelines and gas gathering systems, provide various ancillary services, and offer 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, Pipelines and Field Services (formerly Pipelines and Gathering) and Other Operations.

CenterPoint Energy was a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (the 1935 Act). The 1935 Act and related rules and regulations imposed a number of restrictions on the activities of CenterPoint Energy and those of its subsidiaries. The Energy Policy Act of 2005 (Energy Act) repealed the 1935 Act effective February 8, 2006, 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 a new Public Utility Holding Company Act of 2005 (PUHCA 2005), which grants to the Federal Energy Regulatory Commission (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. On December 8, 2005, the FERC issued rules implementing PUHCA 2005 that will require CenterPoint Energy to notify the FERC of its status as a holding company and to maintain certain books and records and make these available to the FERC. The FERC continues to consider motions for rehearing or clarification of these rules.

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 website are not incorporated by reference herein.

NATURAL GAS DISTRIBUTION

Our natural gas distribution business engages in regulated intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas through two unincorporated divisions: Minnesota Gas and Southern Gas Operations.

Minnesota Gas provides natural gas distribution services to approximately 780,000 customers in over 240 communities. The largest metropolitan area served by Minnesota Gas is Minneapolis. In 2005, approximately 44% of Minnesota Gas' total throughput was attributable to residential customers and approximately 56% was attributable to commercial and industrial customers. Minnesota Gas also provides unregulated services consisting of heating, ventilating and air conditioning (HVAC) equipment and appliance repair, sales of HVAC, water heating and hearth equipment and home security monitoring.

Southern Gas Operations provides natural gas distribution services to approximately 2.3 million customers in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. The largest metropolitan areas served by Southern Gas

Operations are Houston, Texas; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. In 2005, approximately 42% of Southern Gas Operations' total throughput was attributable to residential customers and approximately 58% was attributable to commercial and industrial customers.

The demand for intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers is seasonal. In 2005, approximately 70% of the total throughput of our local distribution companies' 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 2005, Minnesota Gas purchased virtually all of its natural gas supply pursuant to contracts with remaining terms varying from a few months to four years. Minnesota Gas' major suppliers in 2005 included BP Canada Energy Marketing Corp. (54% of supply volumes), Tenaska Marketing Ventures (11%), ONEOK Energy Services Company, LP (7%) and ConocoPhillips Company (5%). Numerous other suppliers provided the remaining 23% of Minnesota Gas' natural gas supply requirements. Minnesota Gas transports its natural gas supplies through various interstate pipelines under contracts with remaining terms, including extensions, varying from one to sixteen years. We anticipate that these gas supply and transportation contracts will be renewed prior to their expiration.

In 2005, Southern Gas Operations purchased virtually all of its natural gas supply pursuant to contracts with remaining terms varying from a few months to five years. Southern Gas Operations' major suppliers in 2005 included Energy Transfer Company (24% of supply volumes), Kinder Morgan Texas Pipeline Corporation (18%), BP Energy Company (12%), Merrill Lynch Commodities (9%), ONEOK Energy Services Company, LP (7%), and Coral Energy LLC (5%). Numerous other suppliers provided the remaining 25% of Southern Gas Operations' natural gas supply requirements. Southern Gas Operations transports its natural gas supplies through various intrastate and interstate pipelines including CenterPoint Energy's pipeline subsidiaries.

Generally, the regulations of the states in which our natural gas distribution business operates allow it to pass through changes in the costs of natural gas 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.

Minnesota Gas and Southern Gas Operations use various leased or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. Minnesota Gas also supplements contracted supplies and storage from time to time with stored liquefied natural gas and propane-air plant production.

Minnesota Gas 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 204 MMcf per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf gas equivalent). Minnesota Gas 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, we enter into contracts to provide sufficient supplies and pipeline capacity to meet its customer requirements. However, it is possible for limited service disruptions of interruptible customers' load 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, 2005, we owned approximately 66,000 linear miles of 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 we serve, we own 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 we receive gas are owned, operated and maintained by others, and our 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

We compete 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 our 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 a number of wholly-owned subsidiaries, primarily CenterPoint Energy Services, Inc. (CES). We have reorganized the oversight of our Natural Gas Distribution business segment and, as a result, beginning in the fourth quarter of 2005, we have established a new reportable business segment, Competitive Natural Gas Sales and Services. These operations were previously reported as part of the Natural Gas Distribution business segment.

In 2005, CES marketed approximately 538 Bcf (including 27 Bcf to affiliates) of natural gas, transportation and related energy services to nearly 7,000 customers which vary in size from small commercial to large utility companies in the central and eastern regions of the United States. The business has three operational functions: wholesale, retail and intrastate pipelines 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 and electric generation customers.

Retail Operations. CES also offers a variety of natural gas management services to smaller commercial and industrial customers, whose facilities are located downstream of natural gas distribution utility city gate stations, including 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. Another wholly owned subsidiary of ours owns and operates approximately 210 miles of intrastate pipeline in Louisiana and Texas. This subsidiary provides bundled and unbundled merchant and transportation services to shippers and end-users.

CES currently transports natural gas on over 30 pipelines throughout the central and eastern United States. CES maintains a portfolio of natural gas supply contracts and firm transportation 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 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 all supply imbalances on a real-time basis to ensure that CES' exposure to commodity price and volume risk is kept to a minimum. The value assigned to these volumetric imbalances is calculated daily and is known as the aggregate Value at Risk (VaR). In 2005, CES' VaR averaged $0.5 million with a high of $3 million.

The CenterPoint Energy Risk Control policy, governed by the Risk Oversight Committee, defines authorized and prohibited trading instruments and volumetric 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.

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.

PIPELINES AND FIELD SERVICES

Our pipelines and field services business operates two interstate natural gas pipelines, as well as gas gathering and processing facilities and also provides operating and technical services and remote data monitoring and communication services. The rates charged by interstate pipelines for interstate transportation and storage services are regulated by the FERC.

We own and operate gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. Our pipeline operations are primarily conducted by two wholly owned interstate pipeline subsidiaries which 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.

Our pipeline project management and facility operation services are provided to affiliates and third parties through a wholly owned pipeline services subsidiary, CenterPoint Energy Pipeline Services, Inc.

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 Midcontinent basin of the United States that interconnect with CEGT's and MRT's pipelines, as well as other interstate and intrastate pipelines. CEFS operates gathering pipelines, which collect natural gas from approximately 200 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas. 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 9,100 locations across Alabama, Arkansas, Colorado, Illinois, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, Texas and Wyoming.

In 2005, approximately 20% of our total operating revenue from pipelines and field services was attributable to services provided to Southern Gas Operations and approximately 7% was attributable to services provided to Laclede Gas Company (Laclede), an unaffiliated distribution company that provides natural gas utility service to the greater St. Louis metropolitan area in Illinois and Missouri. Services to Southern Gas Operations and Laclede are provided under several long-term firm storage and transportation agreements. The agreement to provide services to

Laclede expires in 2007. We expect that this agreement will be renewed prior to its expiration. Agreements for firm transportation, "no notice" transportation service and storage service in Southern Gas Operations' major service areas (Arkansas, Louisiana and Oklahoma) expire in 2012.

In October 2005, CEGT signed a firm transportation agreement with XTO Energy 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 is in the process of filing applications for certificates with the FERC to build a 172 mile, 42-inch diameter pipeline, and related compression facilities at an estimated cost of $400 million. The final capacity of the pipeline will be between 960 MMcf per day and 1.24 Bcf per day. CEGT expects to have firm contracts for the full capacity of the pipeline prior to its expected in service date in early 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, CEGT would construct a 67 mile extension from CEGT's Perryville hub to an interconnect with Texas Eastern Gas Transmission at Union Church, Mississippi.

Our pipelines and 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 Midcontinent and Gulf Coast natural gas supply regions and general economic conditions.

Assets

We own and operate approximately 8,200 miles of gas transmission lines primarily located in Missouri, Illinois, Arkansas, Louisiana, Oklahoma and Texas. We also own and operate 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. We also own a 10% interest in Gulf South Pipeline Company, LP's Bistineau storage facility. 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. We also own and operate approximately 4,000 miles of gathering pipelines that collect, treat and process natural gas from approximately 200 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Competition

Our pipelines and field services business competes with other interstate and intrastate pipelines and gathering companies 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 pipelines and 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 transportation and storage services. In addition, competition for our gathering operations is impacted by commodity pricing levels because of their influence on the level of drilling activity. Both pipeline services and ServiceStar compete with other similar service companies based on market pricing. The principal elements of competition are rates, terms of service and reliability of services.

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.

PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

As a subsidiary of a registered public utility holding company under the 1935 Act, we were subject to a comprehensive regulatory scheme imposed by the SEC. 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 effective February 8, 2006, and since that date, we 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. On December 8, 2005, the FERC issued rules implementing PUHCA 2005 that will require our parent to notify the FERC of its status as a holding company and to maintain certain books and records and make these available to the FERC. The FERC continues to consider motions for rehearing or clarification of these rules.

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 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.

STATE AND LOCAL REGULATION

In almost all communities in which we provide natural gas distribution services, we operate 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, though franchises in Arkansas are perpetual. None of our material franchises expire in the near term. We expect to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of our retail natural gas sales by our local distribution divisions are 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 certain municipalities we serve.

SOUTHERN GAS OPERATIONS

In November 2004, Southern Gas Operations filed an application for a $34 million base rate increase, which was subsequently adjusted downward to $28 million, with the Arkansas Public Service Commission (APSC). In September 2005, an $11 million rate reduction (which included a $10 million reduction relating to depreciation rates) ordered by the APSC went into effect. The reduced depreciation rates were implemented effective October 2005. This base rate reduction and corresponding reduction in depreciation expense represent an annualized operating income reduction of $1 million.

In April 2005, the Railroad Commission established new gas tariffs that increased Southern Gas Operations' base rate and service revenues by a combined $2 million in the unincorporated environs of its Beaumont/East Texas and South Texas Divisions. In June and August 2005, Southern Gas Operations filed requests to implement these same rates within 169 incorporated cities located in the two divisions. The proposed rates were approved or became effective by operation of law in 164 of these cities. Five municipalities denied the rate change requests within their respective jurisdictions. Southern Gas Operations has appealed the actions of these five cities to the Railroad Commission. In February 2006, Southern Gas Operations notified the Railroad Commission that it had reached a settlement with four of the five cities. If approved, the settlement will affect rates in a total of 60 cities in the South Texas Division. In addition, 19 cities where rates have already gone into effect have challenged the jurisdictional and statutory basis for implementation of the new rates within their respective jurisdictions. Southern Gas Operations has petitioned the Railroad Commission for an order declaring that the new rates have been properly established within these 19 cities. If the settlement is approved and assuming all other rate change proposals become effective, revenues from Southern Gas Operations' base rates and miscellaneous service charges would increase by an additional $17 million annually. Currently, approximately $15 million of this expected annual increase is in effect in the incorporated areas of Southern Gas Operations' Beaumont/East Texas and South Texas Divisions.

In October 2005, Southern Gas Operations filed requests with the Louisiana Public Service Commission (LPSC) for approximately $2 million in base rate increases for its South Louisiana service territory and approximately $2 million in base rate reductions for its North Louisiana service territory in accordance with the Rate Stabilization Plans in its tariffs. These base rate changes became effective on January 2, 2006 in accordance with the tariffs and are subject to review and possible adjustment by the staff of the LPSC. Southern Gas Operations is unable to predict when the LPSC staff may conclude its review or what adjustments, if any, the staff may recommend.

In December 2005, Southern Gas Operations filed a request with the Mississippi Public Service Commission (MPSC) for approximately $1 million in miscellaneous service charges (e.g., charges to connect service, charges for returned checks, etc.) in its Mississippi service territory. This request was approved in the first quarter of 2006.

In addition, in January and February 2006, Southern Gas Operations filed requests with the MPSC for approximately $3 million in base rate increases in its Mississippi service territory in accordance with the Automatic Rate Adjustment Mechanism provisions in its tariffs and an additional $2 million in surcharges to recover system restoration expenses incurred following hurricane Katrina. Both requests are being reviewed by the MPSC staff with a decision expected in the first quarter of 2006.

MINNESOTA GAS

In June 2005, the Minnesota Public Utilities Commission (MPUC) approved a settlement which increased Minnesota Gas' base rates by approximately $9 million annually. An interim rate increase of approximately $17 million had been implemented in October 2004. Substantially all of the excess amounts collected in interim rates over those approved in the final settlement were refunded to customers in the third quarter of 2005.

In November 2005, Minnesota Gas 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. A decision by the MPUC is expected in the third quarter of 2006.

In December 2004, the MPUC opened an investigation to determine whether Minnesota Gas' practices regarding restoring natural gas service during the period between October 15 and April 15 (Cold Weather Period) are in compliance with the MPUC's Cold Weather Rule (CWR), which governs disconnection and reconnection of customers during the Cold Weather Period. The Minnesota Office of the Attorney General (OAG) issued its report alleging Minnesota Gas has violated the CWR and recommended a $5 million penalty. Minnesota Gas and the OAG have reached an agreement on procedures to be followed for the current Cold Weather Period which began on October 15, 2005. 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 Minnesota Gas' conduct under the CWR was in violation of the law. Minnesota Gas is in settlement discussions regarding both the OAG's action and the action on behalf of the purported class.

DEPARTMENT OF TRANSPORTATION

In December 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (the Act). This legislation applies to our interstate pipelines as well as our intrastate pipelines 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.

Final regulations implementing the Act became effective on February 14, 2004 and provided guidance on, among other things, the areas that should be classified as HCA.

Our interstate and intrastate pipelines and our natural gas distribution companies anticipate that compliance with these regulations will require increases in both capital and operating cost. 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, gas gathering and processing systems, and electric transmission and distribution systems we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of our 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 the various environmental remediation activities in which we are presently engaged 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 any 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 are 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 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 actions 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. 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. In the pending litigation, the plaintiffs seek monetary damages for alleged damage to the aquifer underlying their property, unspecified alleged personal injuries, alleged fear of cancer, alleged property damage or diminution of value of their property, and, in addition, seek damages for trespass, punitive, and exemplary damages. We believe the ultimate cost associated with resolving this matter will not have a material impact on our financial condition or results of operations.

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, 2005, we had accrued $14 million for remediation of these Minnesota sites. At December 31, 2005, 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, 2005, we have collected $13 million from insurance companies and ratepayers 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 or operated by one of our former affiliates. We have been named as a defendant in two lawsuits 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 court considering the other suit for contribution granted our motion to dismiss on the grounds that we were not an "operator" of the site as had been alleged. The plaintiff in that case has filed an appeal of the court's dismissal of us. 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 is vigorously contesting those suits and our designation as a PRP.

Mercury Contamination. Our pipeline and natural gas 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 cannot be 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.

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. Although their ultimate outcome cannot be predicted at this time, we do not believe, based on our experience to date, that these matters, either individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

EMPLOYEES

As of December 31, 2005, we had 5,202 full-time employees. The following table sets forth the number of our employees by business segment as of December 31, 2005:

BUSINESS SEGMENT	NUMBER	NUMBER REPRESENTED BY UNIONS OR OTHER COLLECTIVE BARGAINING GROUPS
Natural Gas Distribution	4,387	1,493
Competitive Natural Gas Sales and Services	98	--
Pipelines and Field Services	717	--
Total	5,202	1,493

As of December 31, 2005, approximately 29% of our employees are subject to collective bargaining agreements. Minnesota Gas has 466 bargaining unit employees who are covered by a collective bargaining unit agreement with the United Association of Journeymen and Apprentices of Plumbing and Pipe Fitting Industry of the United States and Canada Local 340 that expires in April 2006. We have a good relationship with this bargaining unit and expect to renegotiate a new agreement in 2006.

ITEM 1A. RISK FACTORS

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 LEAD TO LESS NATURAL GAS BEING MARKETED, AND OUR 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. They 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, which has been the trend in recent years. 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 gas prices could create the need for us to provide collateral in order to purchase gas.

IF WE WERE TO FAIL TO EXTEND A CONTRACT WITH ONE OF OUR SIGNIFICANT PIPELINE CUSTOMERS, THERE COULD BE AN ADVERSE IMPACT ON OUR OPERATIONS.

Our contract with Laclede Gas Company, one of our pipeline's customers, is currently scheduled to expire in 2007. To the extent the pipeline is unable to extend this contract or the contract is renegotiated at rates substantially less 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.

OUR PIPELINES' AND FIELD SERVICES' BUSINESS REVENUES AND RESULTS OF OPERATIONS ARE SUBJECT TO FLUCTUATIONS IN THE SUPPLY OF GAS.

Our pipelines and field services business largely relies on gas sourced in the various supply basins located in the Midcontinent 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.

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, 2005, we had $2 billion of outstanding indebtedness on a consolidated basis. As of December 31, 2005, approximately $465 million principal amount of this debt must be paid through 2008. 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 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, 2005, CenterPoint Energy and its other subsidiaries have approximately $200 million principal amount of debt required to be paid through 2008. This amount excludes amounts related to capital leases, securitization debt and indexed debt securities obligations. In addition, CenterPoint Energy has $830 million of outstanding convertible notes on which holders could exercise their "put" rights during this period. 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.

RISKS COMMON TO OUR BUSINESSES AND OTHER RISKS

WE ARE SUBJECT TO OPERATIONAL AND FINANCIAL RISKS AND LIABILITIES ARISING FROM ENVIRONMENTAL LAWS AND REGULATIONS.

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

- restricting the way we can handle or dispose of our 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 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. The 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 when separation occurred in September 2002, RRI had been unable to extinguish all obligations. To secure CenterPoint Energy and us against obligations under the remaining guarantees, 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 guarantees. Our current exposure under the remaining guarantees 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 in 2006 through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. As a result of changes in market conditions, our potential exposure under that guaranty currently exceeds 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, and we and RRI are pursuing alternatives. RRI continues to meet its obligations under the transportation contracts.

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

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 "Our Business -- Natural Gas Distribution" in Item 1 of this report, which information is incorporated herein by reference.

PIPELINES AND FIELD SERVICES

For information regarding the properties of our Pipelines and Field Services business segment, please read "Our Business -- Pipelines and Field Services" 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 "Regulation" and "Environmental Matters" in Item 1 of this report and Notes 3, 8(d) and 8(e) 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 2004 and 2005, we paid dividends on our common stock of $13 million and $100 million, respectively, to Utility Holding, LLC.

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 for the year ended December 31, 2005 was 2.64.

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), a public utility holding company. We own gas distribution systems serving approximately 3.1 million customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. Through wholly owned subsidiaries, we also own two interstate natural gas pipelines and gas gathering systems, provide various ancillary services, and offer variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

CenterPoint Energy was a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (the 1935 Act). The 1935 Act and related rules and regulations imposed a number of restrictions on CenterPoint Energy's activities and those of its subsidiaries. The Energy Policy Act of 2005 (Energy Act) repealed the 1935 Act effective February 8, 2006, 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 a new Public Utility Holding Company Act of 2005 (PUHCA 2005), which grants to the Federal Energy Regulatory Commission (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. On December 8, 2005, the FERC issued rules implementing PUHCA 2005 that will require CenterPoint Energy to notify the FERC of its status as a holding company and to maintain certain books and records and make these available to the FERC. The FERC continues to consider motions for rehearing or clarification of these rules.

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 also subject to rate regulation and are reported in the Natural Gas Distribution business segment. Our reportable business segments include:

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 3.1 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 natural gas sales and services provided primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. We have reorganized the oversight of our Natural Gas Distribution business segment and, as a result, beginning in the fourth quarter of 2005, we have established a new reportable business segment, Competitive Natural Gas Sales and Services. These operations were previously reported as part of the Natural Gas Distribution business segment. We have reclassified all prior period segment information to conform to this new presentation.

Pipelines and Field Services (formerly Pipelines and Gathering)

Our pipelines and field services business owns and operates approximately 8,200 miles of gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. Our pipelines and field services business 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. Most storage operations are in north Louisiana and Oklahoma. Our pipelines and field services business also owns and operates approximately 4,000 miles of gathering pipelines that collect, treat and process natural gas from approximately 200 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.

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;

- 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;

- 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 for the years ended December 31, 2003, 2004 and 2005, 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,		
	2003	2004	2005
	(IN MILLIONS)		
Revenues	$5,650	$6,472	$8,070
Expenses:			
Natural gas	4,297	5,013	6,509
Operation and maintenance	688	732	743
Depreciation and amortization	176	187	198
Taxes other than income taxes	130	147	156
Total	5,291	6,079	7,606
Operating Income	359	393	464
Interest and other finance charges	(179)	(178)	(176)
Other income, net	8	16	21
Income Before Income Taxes	188	231	309
Income Tax Expense	59	87	116
Net Income	$ 129	$ 144	$ 193

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 $55 million in our Pipelines and Field Services business segment resulting from increased demand for transportation resulting from basis differentials across the system and higher demand for ancillary services as well as increased throughput and demand for services related to our core gas gathering operations and increased operating income of $16 million in our Competitive Natural Gas Sales and Services business segment primarily due to higher wholesale sales to utilities and favorable basis differentials over the pipeline capacity that we control, 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.

2004 Compared to 2003. We reported net income of $144 million for 2004 as compared to $129 million for 2003. The increase in net income of $15 million was primarily due to increased operating income of $21 million in our Natural Gas Distribution business segment, primarily due to rate increases, and increased operating income of

$22 million in our Pipelines and Field Services business segment, primarily from increased throughput, favorable commodity prices and increased ancillary services.

Our effective tax rate for 2004 and 2003 was 37.5% and 31.3%, respectively. The increase in the effective rate for 2004 compared to 2003 was primarily the result of a non-recurring decreased tax expense in 2003 relating to our Minnesota operations.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

Revenues by segment include intersegment sales, which are eliminated in consolidation.

The following tables present operating income for our Natural Gas Distribution, Competitive Natural Gas Sales and Services, and Pipelines and Field Services business segments for 2003, 2004 and 2005. Some amounts from the previous years have been reclassified to conform to the 2005 presentation of the financial statements. These reclassifications do not affect consolidated operating income.

NATURAL GAS DISTRIBUTION

The following table provides summary data of our Natural Gas Distribution business segment for 2003, 2004 and 2005 (in millions, except throughput and customer data):

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
Revenues	$ 3,389	$ 3,579	$ 3,846
Expenses:			
Natural gas	2,450	2,596	2,841
Operation and maintenance	540	544	551
Depreciation and amortization	135	141	152
Taxes other than income taxes	107	120	127
Total expenses	3,232	3,401	3,671
Operating Income	$ 157	$ 178	$ 175
Throughput (in billion cubic feet (Bcf)):			
Residential	183	175	160
Commercial and industrial	238	237	215
Total Throughput	421	412	375
Average number of customers:			
Residential	2,755,200	2,798,210	2,838,357
Commercial and industrial	245,081	246,068	246,372
Total	3,000,281	3,044,278	3,084,729

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 (revenues less natural gas costs) 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 since December 2004 ($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 will not be taking service for the foreseeable future. The impact on the Natural Gas Distribution business segment's operating income was not material.

2004 Compared to 2003. Our Natural Gas Distribution business segment reported operating income of $178 million for 2004 as compared to $157 million for 2003. Increases in operating income of $4 million from continued customer growth with the addition of 45,000 customers since December 31, 2003, $15 million from rate increases, $11 million from the impact of the 2003 change in estimate of margins earned on unbilled revenues implemented in 2003 and $9 million related to certain regulatory adjustments made to the amount of recoverable gas costs in 2003 were partially offset by the $8 million impact of milder weather. Operations and maintenance expense increased $4 million for 2004 as compared to 2003. Excluding an $8 million charge recorded in the first quarter of 2004 for severance costs associated with staff reductions, which has reduced costs in later periods, operation and maintenance expenses decreased by $4 million.

COMPETITIVE NATURAL GAS SALES AND SERVICES

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for 2003, 2004 and 2005 (in millions, except throughput and customer data):

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
Revenues	$2,232	$2,848	$4,129
Expenses:			
Natural gas	2,164	2,778	4,033
Operation and maintenance	20	22	30
Depreciation and amortization	1	2	2
Taxes other than income taxes	2	2	4
Total expenses	2,187	2,804	4,069
Operating Income	$ 45	$ 44	$ 60
Throughput (in Bcf):			
Wholesale - third parties	195	228	304
Wholesale - affiliates	21	35	27
Retail	140	141	156
Pipeline	80	76	51
Total Throughput	436	480	538
Average number of customers:			
Wholesale	73	97	138
Retail	5,242	5,976	6,328
Pipeline	188	172	142
Total	5,503	6,245	6,608

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).

2004 Compared to 2003. Our Competitive Natural Gas Sales and Services business segment reported operating income of $44 million for 2004 as compared to $45 million for 2003. The decrease in operating income was primarily due to increased payroll and benefit-related expenses ($3 million), increased factoring expenses ($1 million) and increased franchise taxes ($1 million), partially offset by increased operating margins related to increased volatility and growth ($2 million) and a decrease in bad debt expense ($2 million).

PIPELINES AND FIELD SERVICES

The following table provides summary data of our Pipelines and Field Services business segment for 2003, 2004 and 2005 (in millions, except throughput data):

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
Revenues	$ 407	$ 451	$ 493
Expenses:			
Natural gas	61	46	30
Operation and maintenance	129	164	164
Depreciation and amortization	40	44	45
Taxes other than income taxes	19	17	19
Total expenses	249	271	258
Operating Income	$ 158	$ 180	$ 235
Throughput (in Bcf):			
Natural gas sales	9	11	6
Transportation	794	859	914
Gathering	292	321	353
Elimination(1)	(4)	(7)	(4)
Total Throughput	1,091	1,184	1,269

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(1) Elimination of volumes both transported and sold.

2005 Compared to 2004. Our Pipelines and Field Services business segment reported operating income of $235 million for 2005 compared to $180 million for 2004. Operating income for the pipeline business for 2005 was $165 million compared to $129 million in 2004. The field services business recorded operating income of $70 million for 2005 compared to $51 million in 2004. Operating margins (revenues less natural gas costs) increased by $58 million primarily due to increased demand for transportation resulting from basis differentials across the system and higher demand for ancillary services ($43 million), increased throughput and demand for services related to our core gas gathering operations ($29 million), partially offset by reductions in project-related revenues ($11 million). Additionally, operation and maintenance expenses remained flat primarily due to a reduction in project-related expenses ($9 million), offset by increases in materials and supplies and contracts and services ($8 million).

2004 Compared to 2003. Our Pipelines and Field Services business segment's operating income increased by $22 million in 2004 compared to 2003. Operating margins (revenues less fuel costs) increased by $59 million primarily due to favorable commodity pricing ($3 million), increased demand for certain transportation services driven by commodity price volatility ($36 million) and increased throughput and enhanced services related to our core gas gathering operations ($11 million). The increase in operating margin was partially offset by higher operation and maintenance expenses of $35 million primarily due to compliance with pipeline integrity regulations ($4 million) and costs relating to environmental matters ($9 million). Project work expenses included in operation and maintenance expense increased ($11 million) resulting in a corresponding increase in revenues billed for these services ($15 million).

Additionally, included in other income in 2003, 2004 and 2005 is equity income of $-0-, $2 million and $6 million, respectively, related to a joint venture owned by our field services business.

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 2006 are approximately $668 million of capital expenditures, including $343 million for the construction of a new pipeline by our Pipelines and Field Services business segment and $154 million principal amount of maturing debt. We expect that borrowings under our credit facility, anticipated cash flows from operations and borrowings from affiliates will be sufficient to meet our cash needs for 2006.

Capital Requirements. We anticipate investing up to an aggregate $2 billion in capital expenditures in the years 2006 through 2010. The following table sets forth our capital expenditures for 2005 and estimates of our capital requirements for 2006 through 2010 (in millions):

2005	$417
2006	668
2007	512
2008	383
2009	362
2010	284

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

CONTRACTUAL OBLIGATIONS	TOTAL	2006	2007-2008	2009-2010	2011 AND THEREAFTER
Long-term debt, including current portion ..	$1,992	$ 154	$ 314	$ 12	$1,512
Interest payments (1)	846	149	260	230	207
Operating leases(2)	70	14	23	11	22
Benefit obligations(3)	--	--	--	--	--
Purchase obligations(4)	109	109	--	--	--
Non-trading derivative liabilities	78	43	20	12	3
Other commodity commitments(5)	1,316	858	428	7	23
Total contractual cash obligations	$4,411	$1,327	$1,045	$272	$1,767

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(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, 2005; 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 $13 million to our postretirement benefits plan in 2006 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 Pipelines and Field Services 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.

Off-Balance Sheet Arrangements. Other than operating leases, we have no off-balance sheet arrangements. However, we do participate in a receivables factoring arrangement. CERC Corp. has a bankruptcy remote subsidiary, which we consolidate, which was formed for the sole purpose of buying receivables created by us and selling those receivables to an unrelated third-party. This transaction is 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," and, as a result, the related receivables are excluded from the Consolidated Balance Sheet. In January 2006, the $250 million facility, which temporarily increased to $375 million for the period from January 2006 to June 2006, was extended to January 2007. As of December 31, 2005, we had $141 million of advances under our receivables facility.

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 when separation occurred in September 2002, RRI had been unable to extinguish all obligations. To secure CenterPoint Energy and us against obligations under the remaining guarantees, 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 guarantees. Our current exposure under the remaining guarantees 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 in 2006 through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. As a result of changes in market conditions, our potential exposure under that guaranty currently exceeds 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, and we and RRI are pursuing alternatives. RRI continues to meet its obligations under the transportation contracts.

Credit Facilities. In June 2005, we replaced our $250 million three-year revolving credit facility with a $400 million five-year revolving credit facility. Borrowings under this facility may be made at the London inter-bank offer rate (LIBOR) plus 55 basis points, including the facility fee, based on current credit ratings. An additional utilization fee of 10 basis points applies to borrowings whenever more than 50% of the facility is utilized. Changes in credit ratings could lower or raise the increment to LIBOR depending on whether ratings improved or were lowered. Our $400 million credit facility contains covenants, including a total debt to capitalization covenant of 65% and an earnings before interest, taxes, depreciation and amortization (EBITDA) to interest covenant. Borrowings under our $400 million credit facility are available notwithstanding that a material adverse change has occurred or litigation that could be expected to have a material adverse effect has occurred, so long as other customary terms and conditions are satisfied. As of February 28, 2006, our $400 million credit facility was not utilized.

We are currently in compliance with the various business and financial covenants contained in our credit facility.

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 commercial paper. At December 31, 2005 and February 28, 2006, we had borrowings of $289 million and $208 million, respectively, from the money pool. The money pool may not provide sufficient funds to meet our cash needs.

Securities Registered with the SEC. At December 31, 2005, we had a shelf registration statement covering $500 million principal amount of debt securities.

Impact on Liquidity of a Downgrade in Credit Ratings. As of February 28, 2006, 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

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(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 $400 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.

Our $400 million credit facility does not contain a material adverse change clause with respect to borrowings.

CES, a wholly owned subsidiary of CERC Corp. operating in our Competitive Natural Gas Sales and Services business segment, provides comprehensive natural gas sales and services primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. In order to hedge its exposure to natural gas prices, CES uses financial derivatives with provisions standard for the industry that establish credit thresholds and require a party to provide additional collateral on two business days' notice when that party's rating or the rating of a credit support provider for that party (CERC Corp. in this case) falls below those levels. We estimate that as of December 31, 2005, unsecured credit limits extended to CES by counterparties aggregate $128 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.

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, 2006, 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 suppliers;

- increased costs related to the acquisition of gas;

- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;

- various regulatory actions;

- the ability of RRI to satisfy its obligations to us;

- slower customer payments and increased write-offs of receivables due to higher gas prices;

- 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 Pay Dividends. Our bank facility and our receivables facility limit our debt as a percentage of our total capitalization to 65 percent and contain an EBITDA to interest covenant.

Our parent, CenterPoint Energy, was a registered public utility holding company under the 1935 Act. The 1935 Act and related rules and regulations imposed a number of restrictions on CenterPoint Energy's activities and those of its subsidiaries. The Energy Act repealed the 1935 Act effective February 8, 2006, 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 a new 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. On December 8, 2005, the FERC issued rules implementing PUHCA 2005 that will require CenterPoint Energy to notify the FERC of its status as a holding company and to maintain certain books and records and make these available to the FERC. The FERC continues to consider motions for rehearing or clarification of these rules.

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 SFAS No. 142, "Goodwill and Other Intangible Assets." 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.

We perform our goodwill impairment test at least annually and evaluate goodwill when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. Upon adoption of SFAS No. 142, we initially selected January 1 as our annual goodwill impairment testing date. Since the time we selected the January 1 date, our year-end closing and reporting process has been truncated in order to meet the accelerated periodic reporting requirements of the SEC, resulting in significant constraints on our human resources at year-end and during our first fiscal quarter. Accordingly, in order to meet the accelerated reporting deadlines and to provide adequate time to complete the analysis each year, beginning in the third quarter of 2005, we changed the date on which we perform our annual goodwill impairment test from January 1 to July 1. We believe the July 1 alternative date will alleviate the resource constraints that exist during the first quarter and allow us to utilize additional resources in conducting the annual impairment evaluation of goodwill. We performed the test at July 1, 2005, and determined that no impairment charge for goodwill was required. The change is not intended to delay, accelerate or avoid an impairment charge. We believe that this accounting change is an alternative accounting principle that is preferable under the circumstances.

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, 2005, our estimated cost of retiring these assets is approximately $65 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 2006 is estimated to be $16 million based on an expected return on plan assets of 8.5% and a discount rate of 5.7% as of December 31, 2005. Pension expense for the year ended December 31, 2005 was $15 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.

We had no floating-rate obligations at December 31, 2004 and 2005.

At December 31, 2004 and 2005, we had outstanding fixed-rate debt and trust preferred securities aggregating $2.4 billion and $2.0 billion, respectively, in principal amount and having a fair value of $2.7 billion and $2.2

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 $53 million if interest rates were to decline by 10% from their levels at December 31, 2005. 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

To reduce our commodity price risk from market fluctuations in the revenues derived from the sale of natural gas and related transportation, we enter into forward contracts, swaps and options (Non-Trading Energy Derivatives) in order to hedge some expected purchases of natural gas and sales of natural gas (a portion of which are firm commitments at the inception of the hedge). Non-Trading Energy Derivatives are also utilized to fix the price of future operational gas requirements.

We use derivative instruments as economic hedges to offset the commodity 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 earnings based on a hypothetical 10% movement in energy prices. A decrease of 10% in the market prices of energy commodities from their December 31, 2004 levels would have decreased the fair value of our Non-Trading Energy Derivatives by $46 million. At December 31, 2005, the recorded fair value of our Non-Trading Energy Derivatives was a net asset of $157 million. A decrease of 10% in the market prices of energy commodities from their December 31, 2005 levels would have decreased the fair value of our Non-Trading Energy Derivatives by $85 million.

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

- the Non-Trading Energy Derivatives are not closed out in advance of their expected term;

- the Non-Trading Energy Derivatives continue to function effectively as hedges of the underlying risk; and

- as applicable, anticipated underlying transactions settle as expected.

If any of the above-mentioned assumptions ceases to be true, a loss on the derivative instruments may occur, or the options might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first. Non-Trading Energy Derivatives designated and effective as hedges, may still have some percentage which is not effective. The change in value of the Non-Trading Energy Derivatives that represents the ineffective component of the hedges is recorded in our results of operations.

CenterPoint Energy has established 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 our 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, 2004 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, 2005. 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, 2004 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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 24, 2006

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

STATEMENTS OF CONSOLIDATED INCOME

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
	(IN MILLIONS)		
REVENUES	$5,650	$6,472	$8,070
EXPENSES:			
Natural gas	4,297	5,013	6,509
Operation and maintenance	688	732	743
Depreciation and amortization	176	187	198
Taxes other than income taxes	130	147	156
Total	5,291	6,079	7,606
OPERATING INCOME	359	393	464
OTHER INCOME (EXPENSE):			
Interest and other finance charges	(179)	(178)	(176)
Other, net	8	16	21
Total	(171)	(162)	(155)
INCOME BEFORE INCOME TAXES	188	231	309
Income Tax Expense	59	87	116
NET INCOME	$ 129	$ 144	$ 193

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,		
	2003	2004	2005
	(IN MILLIONS)		
Net income	$129	$144	$193
Other comprehensive income (loss), net of tax:			
Net deferred gain from cash flow hedges (net of tax of $15, $31 and $9)	22	59	17
Reclassification of net deferred loss (gain) from cash flow hedges realized in net income (net of tax of $1, ($12) and ($5))	1	(24)	(8)
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)	23	(33)	9
Comprehensive income	$152	$111	$202

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, 2004	DECEMBER 31, 2005
	(IN MILLIONS)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 141	$ 31
Accounts receivable, net	545	942
Accrued unbilled revenue	502	500
Accounts and notes receivable -- affiliated companies, net	12	--
Inventory	201	323
Non-trading derivative assets	50	131
Taxes receivable	155	117
Deferred tax asset	12	17
Prepaid expenses	9	11
Other	92	119
Total current assets	1,719	2,191
PROPERTY, PLANT AND EQUIPMENT, NET	3,834	4,105
OTHER ASSETS:		
Goodwill	1,741	1,709
Other intangibles, net	20	18
Non-trading derivative assets	18	104
Accounts and notes receivable -- affiliated companies, net	18	9
Other	117	165
Total other assets	1,914	2,005
TOTAL ASSETS	$7,467	$8,301
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Current portion of long-term debt	$ 367	$ 154
Accounts payable	733	1,077
Accounts and notes payable -- affiliated companies, net	--	319
Taxes accrued	78	67
Interest accrued	58	46
Customer deposits	60	62
Non-trading derivative liabilities	26	43
Other	273	341
Total current liabilities	1,595	2,109
OTHER LIABILITIES:		
Accumulated deferred income taxes, net	641	663
Non-trading derivative liabilities	6	35
Benefit obligations	128	127
Other	557	716
Total other liabilities	1,332	1,541
LONG-TERM DEBT	2,001	1,838
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
STOCKHOLDER'S EQUITY	2,539	2,813
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$7,467	$8,301

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

STATEMENTS OF CONSOLIDATED CASH FLOWS

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
	(IN MILLIONS)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 129	$ 144	$ 193
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	176	187	198
Deferred income taxes	25	(8)	32
Amortization of deferred financing costs	8	10	9
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(122)	(163)	(393)
Accounts receivable/payable, affiliates	(4)	7	10
Inventory	(51)	(14)	(109)
Taxes receivable	29	118	39
Accounts payable	58	208	326
Fuel cost recovery	25	25	(129)
Interest and taxes accrued	18	11	(23)
Net non-trading derivative assets and liabilities	18	(39)	(12)
Other current assets	(37)	(18)	(31)
Other current liabilities	(1)	(20)	131
Other assets	20	47	8
Other liabilities	40	(6)	30
Other, net	(14)	(3)	(3)
Net cash provided by operating activities	317	486	276
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(265)	(269)	(403)
Decrease (increase) in affiliate notes receivable	5	(30)	42
Other, net	(7)	(3)	(11)
Net cash used in investing activities	(267)	(302)	(372)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments of long-term debt	(508)	--	(372)
Proceeds from long-term debt	928	--	--
Increase (decrease) in short-term borrowings, net	(284)	(63)	--
Increase (decrease) in notes with affiliates, net	(74)	--	288
Contribution from parent	--	--	171
Dividends to parent	--	(13)	(100)
Debt issuance costs	(87)	(1)	(1)
Net cash used in financing activities	(25)	(77)	(14)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	25	107	(110)
CASH AND CASH EQUIVALENTS AT BEGINNING OF THE YEAR	9	34	141
CASH AND CASH EQUIVALENTS AT END OF THE YEAR	$ 34	$ 141	$ 31
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash Payments:			
Interest, net of capitalized interest	$ 164	$ 176	$ 181
Income taxes (refunds)	(49)	42	87
Non-cash transactions:			
Increase in accounts payable related to capital expenditures	$ --	$ --	$ 14

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

	2003		2004		2005	
	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		1,986		1,985		2,232
Contribution from parent		--		247		171
Other		(1)		--		1
Balance, end of year		1,985		2,232		2,404
RETAINED EARNINGS						
Balance, beginning of year		45		174		305
Net income		129		144		193
Dividend to parent		--		(13)		(100)
Balance, end of year		174		305		398
ACCUMULATED OTHER COMPREHENSIVE INCOME						
Balance, end of year:						
Net deferred gain from cash flow hedges		35		2		11
Total accumulated other comprehensive income, end of year		35		2		11
Total Stockholder's Equity		$2,194		$2,539		$2,813

See Notes to the Company's Consolidated Financial Statements

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 facilities, interstate pipelines and natural gas gathering, processing and treating facilities. CERC Corp. is a Delaware corporation.

The Company's operations of its local distribution companies are conducted through two unincorporated divisions: Minnesota Gas and Southern Gas Operations. Through wholly owned subsidiaries, the Company owns two interstate natural gas pipelines and gas gathering systems, provides various ancillary services, and offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

The Company is an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company. CenterPoint Energy was a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (the 1935 Act). The 1935 Act and related rules and regulations imposed a number of restrictions on the activities of CenterPoint Energy and its subsidiaries. The Energy Policy Act of 2005 (Energy Act) repealed the 1935 Act effective February 8, 2006, 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 a new Public Utility Holding Company Act of 2005 (PUHCA 2005), which grants to the Federal Energy Regulatory Commission (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. On December 8, 2005, the FERC issued rules implementing PUHCA 2005 that will require CenterPoint Energy to notify the FERC of its status as a holding company and to maintain certain books and records and make these available to the FERC. The FERC continues to consider motions for rehearing or clarification of these rules.

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

Some amounts from the previous years have been reclassified to conform to the 2005 presentation of financial statements. These reclassifications relate to a new reportable business segment discussed in Note 11 and do not affect net income.

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 significant 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 $13 million and $15 million as of December 31, 2004 and 2005, 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 Pipelines and Field Services business segment records 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, 2004	DECEMBER 31, 2005
		(IN MILLIONS)	
Natural gas distribution	30	$2,475	$2,740
Competitive natural gas sales and services	38	19	27
Pipelines and field services	52	1,767	1,887
Other property	29	35	20
Total		4,296	4,674
Accumulated depreciation and amortization:			
Natural gas distribution		(285)	(391)
Competitive natural gas sales and services		(6)	(5)
Pipelines and field services		(157)	(167)
Other property		(14)	(6)
Total accumulated depreciation and amortization		(462)	(569)
Property, plant and equipment, net		$3,834	$4,105

The components of the Company's other intangible assets consist of the following:

	DECEMBER 31, 2004		DECEMBER 31, 2005	
	CARRYING AMOUNT	ACCUMULATED AMORTIZATION	CARRYING AMOUNT	ACCUMULATED AMORTIZATION
	(IN MILLIONS)			
Land Use Rights	$ 7	$(3)	$ 7	$ (3)
Other	21	(5)	21	(7)
Total	$28	$(8)	$28	$(10)

The Company recognizes specifically identifiable intangibles, including land use rights and permits, when specific rights and contracts are acquired. The Company has no intangible assets with indefinite lives recorded as of December 31, 2005 other than goodwill discussed below. The Company amortizes other acquired intangibles on a straight-line basis over the lesser of their contractual or estimated useful lives that range from 27 to 75 years for land rights and 10 to 56 years for other intangibles.

Amortization expense for other intangibles for each of the years ended December 2003, 2004 and 2005 was $2 million. Estimated amortization expense is approximately $2 million per year for the five succeeding fiscal years.

Goodwill by reportable business segment is as follows (in millions):

	NATURAL GAS DISTRIBUTION	COMPETITIVE NATURAL GAS SALES AND SERVICES	PIPELINES AND FIELD SERVICES	OTHER OPERATIONS	TOTAL
Balance as of December 31, 2004 ...	$746	$339	$601	$ 55	$1,741
Goodwill acquired during year	--	--	3	--	3
Adjustment(1)	--	--	--	(35)	(35)
Balance as of December 31, 2005 ...	$746	$339	$604	$ 20	$1,709

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(1) In December 2005, the Company determined that $35 million of deferred tax liabilities originally established in connection with an acquisition were no longer required. In accordance with Emerging Issues Task Force (EITF) Issue No. 93-7, "Uncertainties Related to Income Taxes in a Purchase Business Combination," the adjustment was applied to decrease the remaining goodwill attributable to that acquisition.

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.

Upon adoption of SFAS No. 142, "Goodwill and Other Intangible Assets," the Company initially selected January 1 as its annual goodwill impairment testing date. Since the time the Company selected the January 1 date, the Company's year-end closing and reporting process has been truncated in order to meet the accelerated reporting requirements of the Securities and Exchange Commission (SEC), resulting in significant constraints on the Company's human resources at year-end and during its first fiscal quarter. Accordingly, in order to meet the accelerated reporting deadlines and to provide adequate time to complete the analysis each year, beginning in the third quarter of 2005, the Company changed the date on which it performs its annual goodwill impairment test from January 1 to July 1. The Company believes the July 1 alternative date will alleviate the resource constraints that exist during the first quarter and allow it to utilize additional resources in conducting the annual impairment evaluation of goodwill. The Company performed the test at July 1, 2005, and determined that no impairment charge for goodwill was required. The change is not intended to delay, accelerate or avoid an impairment charge. The Company believes that this accounting change is an alternative accounting principle that is preferable under the circumstances.

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 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 Pipelines and Gathering business segment.

The following is a list of regulatory assets/liabilities reflected on the Company's Consolidated Balance Sheets as of December 31, 2004 and 2005:

	DECEMBER 31, 2004	DECEMBER 31, 2005
	(IN MILLIONS)	
Regulatory assets in other long-term assets	$ 21	$ 53
Regulatory liabilities in other long-term liabilities	(433)	(434)
Total	$(412)	$(381)

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, 2004 and 2005, these removal costs of $428 million and $406 million, respectively, are classified as regulatory liabilities in the Consolidated Balance Sheets. A portion of the amount of removal costs that relate to asset retirement obligations have been reclassified from a regulatory liability to an asset retirement liability, 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) as further discussed in Note 2(n).

(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 2003, 2004 and 2005:

	YEAR ENDED DECEMBER 31, 2003	2004	2005
	(IN MILLIONS)		
Depreciation expense	$161	$171	$180
Amortization expense	15	16	18
Total depreciation and amortization expense	$176	$187	$198

(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 2003, 2004 and 2005, the Company capitalized interest and AFUDC of $1 million, $2 million and $1 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 both 2004 and 2005, the Company received an allocation of CenterPoint Energy's tax benefits totaling $171 million. 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." 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 $28 million and $38 million at December 31, 2004 and 2005, respectively. The provision for doubtful accounts in the Company's Statements of Consolidated Income for 2003, 2004 and 2005 was $24 million, $26 million and $37 million, respectively.

As of December 31, 2004 and 2005, the Company had $181 million and $141 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. 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 are excluded from the Consolidated Balance Sheets. The bankruptcy remote subsidiary purchases receivables with cash and subordinated notes. The subordinated notes owned by the Company are pledged to a gas supplier to secure obligations incurred in connection with the purchase of gas by the Company and totaled approximately $433 million as of December 31, 2005.

In January 2006, the Company's $250 million receivables facility, which was temporarily increased to $375 million for the period from January 2006 to June 2006 to provide additional liquidity to the Company during the peak heating season of 2006, was extended to January 2007.

Advances under the receivables facility averaged $100 million, $190 million and $166 million in 2003, 2004 and 2005, respectively. Sales of receivables were approximately $1.2 billion, $2.4 billion and $2.0 billion in 2003, 2004 and 2005, 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. Inventories used in the natural gas distribution operations are also primarily valued at the lower of average cost or market.

	DECEMBER 31, 2004	DECEMBER 31, 2005
	(IN MILLIONS)	
Materials and supplies...	$ 25	$ 29
Natural gas.............	176	294
Total inventory.......	$201	$323

(k) INVESTMENT IN OTHER DEBT AND EQUITY SECURITIES

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

As of December 31, 2004 and 2005, the Company held no "available-for-sale" or "trading" securities.

(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 May 2005, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 154, "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3" (SFAS No. 154). SFAS No. 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to the newly adopted accounting principle. The correction of an error in previously issued financial statements is not an accounting change and must be reported as a prior-period adjustment by restating previously issued financial statements. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

In March 2005, the FASB issued FIN 47. FIN 47 clarifies that an entity must record a liability for a "conditional" asset retirement obligation if the fair value of the obligation can be reasonably estimated. The Company has identified conditional asset retirement obligations in the natural gas distribution segment that exist due to requirements of the U.S Department of Transportation to cap and purge certain mains upon retirement. The fair value of these obligations is recorded as a liability on a discounted basis with a corresponding increase to the related asset. Over time, the liabilities are accreted for the change in the present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The adoption of FIN 47, effective December 31, 2005, resulted in the recognition of an asset retirement obligation liability of $65 million, an increase in net property, plant and equipment of $31 million and a $34 million increase in net regulatory assets. The Company's rate-regulated businesses have previously recognized removal costs as a component of depreciation expense in accordance with regulatory treatment, and these costs have been classified as a regulatory liability. Upon adoption of FIN 47, the portion of the removal costs that relates to this asset retirement obligation has been reclassified from a regulatory liability to an asset retirement liability, which is included in other liabilities in the Consolidated Balance Sheets.

The pro forma effect of applying this guidance in the prior periods would have resulted in an asset retirement obligation of approximately $57 million and $61 million as of January 1, 2004 and December 31, 2004, respectively.

In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments" (SFAS No. 155). SFAS No. 155 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and SFAS No. 140. SFAS No. 155 includes provisions that permit fair value remeasurement for any hybrid financial instrument that contains an embedded derivative and that otherwise would require bifurcation. It also establishes a requirement to evaluate interests in securitized financial assets to identify interests that are free-standing or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of the Company's first fiscal year that begins after September 15, 2006. The fair value election in SFAS No. 155 may also be applied upon adoption for hybrid instruments that have been bifurcated under SFAS No. 133 prior to the adoption of this statement. The Company is evaluating the effect of adoption of this new standard on its financial position, results of operations and cash flows and does not expect the standard to have a material impact.

(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 $36 million, $35 million and $15 million for the years ended December 31, 2003, 2004 and 2005, 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 $3 million for the year ended December 31, 2003 and less than $1 million for each of the years ended December 31, 2004 and 2005.

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 $15 million, $16 million and $17 million for the years ended December 31, 2003, 2004 and 2005, 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 2005's net periodic postretirement benefit costs by approximately $5 million, including $2 million of amortization of the actuarial loss, $1 million of reduced service cost and $2 million of reduced interest cost on the accumulated postretirement benefit obligation.

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,		
	2003	2004	2005
	(IN MILLIONS)		
Service cost -- benefits earned during the period...	$ 2	$ 2	$ 1
Interest cost on projected benefit obligation.......	10	10	8
Expected return on plan assets......................	(2)	(2)	(2)
Amortization of prior service cost..................	2	2	2
Other...	--	1	1
Net postretirement benefit cost.....................	$12	$13	$10

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

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
Discount rate.............................	6.75%	6.25%	5.75%
Expected return on plan assets............	9.0%	8.5%	8.0%

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 2004 and 2005.

	YEAR ENDED DECEMBER 31,	
	2004	2005
	(IN MILLIONS)	
CHANGE IN BENEFIT OBLIGATION		
Accumulated benefit obligation, beginning of year	$ 171	$ 174
Service cost	2	1
Interest cost	10	8
Benefit enhancement	1	1
Benefits paid	(21)	(17)
Participant contributions	4	3
Actuarial loss (gain)	7	(38)
Accumulated benefit obligation, end of year	$ 174	$ 132
CHANGE IN PLAN ASSETS		
Plan assets, beginning of year	$ 21	$ 21
Benefits paid	(21)	(17)
Employer contributions	14	12
Participant contributions	4	3
Actual investment return	3	1
Plan assets, end of year	$ 21	$ 20
RECONCILIATION OF FUNDED STATUS		
Funded status	$(153)	$(112)
Unrecognized prior service cost	13	11
Unrecognized actuarial loss	46	9
Net amount recognized in balance sheets	$ (94)	$ (92)
ACTUARIAL ASSUMPTIONS		
Discount rate	5.75%	5.7%
Expected long-term return on assets..................	8.0%	4.8%
Healthcare cost trend rate assumed for the next year..	9.75%	9.0%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate).....................	5.5%	5.5%
Year that the rate reaches the ultimate trend rate....	2011	2011
Measurement date used to determine plan obligations		

and assets..	December 31, 2004	December 31, 2005

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

	1% INCREASE	1% DECREASE
	(IN MILLIONS)	
Effect on the postretirement benefit obligation...	$5	($4)

The following table displays the weighted average asset allocations as of December 31, 2003 and 2004 for the Company's postretirement benefit plan:

	DECEMBER 31,	
	2004	2005
Domestic equity securities........	38%	8%
International equity securities...	11	--
Debt securities...................	50	90
Cash..............................	1	2
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...	4-6%
Debt securities..............	92-94%
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 $13 million to its postretirement benefits plan in 2006.

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

	POSTRETIREMENT BENEFIT PLAN	
	BENEFIT PAYMENTS	MEDICARE SUBSIDY RECEIPTS
2006........	$11	$ (1)
2007........	11	(2)
2008........	11	(2)
2009........	11	(2)
2010........	11	(2)
2011-2015...	61	(10)

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 $5 million, $3 million and $3 million in 2003, 2004 and 2005, respectively.

Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31,2004 and 2005, was $18 million and $19 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 2003, 2004 and 2005, the Company recorded benefits expense relating to these programs of $1 million each year. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2004 and 2005, was $9 million and $7 million, respectively, relating to deferred compensation plans.

3. REGULATORY MATTERS

(a) RATE CASES

SOUTHERN GAS OPERATIONS

In November 2004, Southern Gas Operations filed an application for a $34 million base rate increase, which was subsequently adjusted downward to $28 million, with the Arkansas Public Service Commission (APSC). In September 2005, an $11 million rate reduction (which included a $10 million reduction relating to depreciation rates) ordered by the APSC went into effect. The reduced depreciation rates were implemented effective October 2005. This base rate reduction and corresponding reduction in depreciation expense represent an annualized operating income reduction of $1 million.

In April 2005, the Railroad Commission established new gas tariffs that increased Southern Gas Operations' base rate and service revenues by a combined $2 million in the unincorporated environs of its Beaumont/East Texas and South Texas Divisions. In June and August 2005, Southern Gas Operations filed requests to implement these same rates within 169 incorporated cities located in the two divisions. The proposed rates were approved or became effective by operation of law in 164 of these cities. Five municipalities denied the rate change requests within their respective jurisdictions. Southern Gas Operations has appealed the actions of these five cities to the Railroad Commission. In February 2006, Southern Gas Operations notified the Railroad Commission that it had reached a settlement with four of the five cities. If approved, the settlement will affect rates in a total of 60 cities in the South Texas Division. In addition, 19 cities where rates have already gone into effect have challenged the jurisdictional and statutory basis for implementation of the new rates within their respective jurisdictions. Southern Gas Operations has petitioned the Railroad Commission for an order declaring that the new rates have been properly established within these 19 cities. If the settlement is approved and assuming all other rate change proposals become effective, revenues from Southern Gas Operations' base rates and miscellaneous service charges would increase by an additional $17 million annually. Currently, approximately $15 million of this expected annual increase is in effect in the incorporated areas of Southern Gas Operations' Beaumont/East Texas and South Texas Divisions.

In October 2005, Southern Gas Operations filed requests with the Louisiana Public Service Commission (LPSC) for approximately $2 million in base rate increases for its South Louisiana service territory and approximately $2 million in base rate reductions for its North Louisiana service territory in accordance with the Rate Stabilization Plans in its tariffs. These base rate changes became effective on January 2, 2006 in accordance with the tariffs and are subject to review and possible adjustment by the staff of the LPSC. Southern Gas Operations is unable to predict when the LPSC staff may conclude its review or what adjustments, if any, the staff may recommend.

In December 2005, Southern Gas Operations filed a request with the Mississippi Public Service Commission (MPSC) for approximately $1 million in miscellaneous service charges (e.g., charges to connect service, charges for returned checks, etc.) in its Mississippi service territory. This request was approved in the first quarter of 2006.

In addition, in January and February 2006, Southern Gas Operations filed requests with the MPSC for approximately $3 million in base rate increases in its Mississippi service territory in accordance with the Automatic Rate Adjustment Mechanism provisions in its tariffs and an additional $2 million in surcharges to recover system restoration expenses incurred following hurricane Katrina. Both requests are being reviewed by the MPSC staff with a decision expected in the first quarter of 2006.

MINNESOTA GAS

In June 2005, the Minnesota Public Utilities Commission (MPUC) approved a settlement which increased Minnesota Gas' base rates by approximately $9 million annually. An interim rate increase of approximately $17 million had been implemented in October 2004. Substantially all of the excess amounts collected in interim rates over those approved in the final settlement were refunded to customers in the third quarter of 2005.

In November 2005, Minnesota Gas 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. A decision by the MPUC is expected in the third quarter of 2006.

In December 2004, the MPUC opened an investigation to determine whether Minnesota Gas' practices regarding restoring natural gas service during the period between October 15 and April 15 (Cold Weather Period) are in compliance with the MPUC's Cold Weather Rule (CWR), which governs disconnection and reconnection of customers during the Cold Weather Period. The Minnesota Office of the Attorney General (OAG) issued its report alleging Minnesota Gas has violated the CWR and recommended a $5 million penalty. Minnesota Gas and the OAG have reached an agreement on procedures to be followed for the current Cold Weather Period which began on October 15, 2005. 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 Minnesota Gas' conduct under the CWR was in violation of the law. Minnesota Gas is in settlement discussions regarding both the OAG's action and the action on behalf of the purported class. 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.

(b) CITY OF TYLER, TEXAS DISPUTE

In July 2002, the City of Tyler, Texas, asserted that Southern 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 by agreement of the parties for a determination of whether Southern 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 December 2004, the Railroad Commission conducted a hearing on the matter. In May 2005, the Railroad Commission issued a final order finding that the Company had complied with its tariffs, acted prudently in entering into its gas supply contracts, and prudently managed those contracts. In August 2005, the City of Tyler appealed this order to the Court of Appeals.

(c) SETTLEMENT OF FERC AUDIT

In June 2005, CenterPoint Energy Gas Transmission Company (CEGT), a subsidiary of CERC Corp., received an Order from the FERC accepting the terms of a settlement agreed upon by CEGT with the Staff of the FERC's Office of Market Oversight and Investigations (OMOI). The settlement brought to a conclusion an investigation of CEGT initiated by OMOI in August 2003. Among other things, the investigation involved a comprehensive review of CEGT's relationship with its marketing affiliates and compliance with various FERC record-keeping and reporting requirements covering the period from January 1, 2001 through September 22, 2004.

OMOI Staff took the position that some of CEGT's actions resulted in a limited number of violations of the FERC's affiliate regulations or were in violation of certain record-keeping and administrative requirements. OMOI did not find any systematic violations of its rules governing communications or other relationships among affiliates.

The settlement included two remedies: a payment of a $270,000 civil penalty and the execution of a compliance plan, applicable to both CEGT and CenterPoint Energy-Mississippi River Transmission Corporation (MRT). The compliance plan consists of a detailed set of Implementation Procedures that will facilitate compliance with the FERC's Order No. 2004, the Standards of Conduct, which regulate behavior between regulated entities and their affiliates. The Company does not believe the compliance plan will have any material effect on CEGT's or MRT's ability to conduct their business.

4. RELATED PARTY TRANSACTIONS

The following table summarizes receivables from, or payables to, CenterPoint Energy or its subsidiaries:

	DECEMBER 31, 2004	DECEMBER 31, 2005
	(IN MILLIONS)	
Accounts receivable from affiliates	$ 4	$ 4
Accounts payable to affiliates	(34)	(34)
Notes receivable from/(payable to) affiliates(1) ..	42	(289)
Accounts and notes receivable/(payable) -- affiliated companies, net	$ 12	$(319)
Long-term accounts receivable from affiliates	$ 64	$ 29
Long-term accounts payable to affiliates	(45)	(20)
Long-term notes payable to affiliates	(1)	--
Long-term accounts and notes receivable -- affiliated companies, net	$ 18	$ 9

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(1) 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 commercial paper. The Company's money pool borrowings of $289 million at December 31, 2005 had a weighted average interest rate of 4.7%.

For the years ended December 31, 2003, 2004 and 2005, the Company had net interest income related to affiliate borrowings of $3 million, $9 million and $3 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 assets, operating expenses 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 $113 million, $116 million and $129 million for 2003, 2004 and 2005, respectively, and are included primarily in operation and maintenance expenses.

Pursuant to the tax sharing agreement with CenterPoint Energy, the Company received an allocation of CenterPoint Energy's tax benefits of $171 million for both 2004 and 2005, which was recorded as an increase to additional paid-in capital.

In 2004 and 2005, the Company paid dividends of $13 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 financial 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. During 2005, hedge ineffectiveness was a loss of $2 million from derivatives that qualify for and are designated as cash flow hedges. No component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness. If it becomes probable that an anticipated transaction will not occur, the Company realizes in net income the deferred gains and losses recognized in accumulated other comprehensive loss. Once the anticipated transaction occurs, 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 Statements of Consolidated Cash Flows in the same category as the item being hedged. As of December 31, 2005, the Company expects $10 million 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 on existing financial instruments is primarily two years with a limited amount of exposure up to ten years. The Company's policy is not to exceed ten years in hedging its exposure.

Other Derivative Financial Instruments. The Company also has natural gas contracts that are derivatives which are not hedged and are accounted for on a mark-to-market basis with changes in fair value reported through earnings. Load following services that the Company offers its natural gas customers create an inherent tendency for the Company to be either long or short natural gas supplies relative to customer purchase commitments. The Company measures and values all of its volumetric imbalances on a real-time basis to minimize its exposure to commodity price and volume risk. The Company does not engage in proprietary or speculative commodity trading. Unhedged positions are accounted for by adjusting the carrying amount of the contracts to market and recognizing any gain or loss in operating income, net. During 2005, the Company recognized net gains related to unhedged positions amounting to $8 million. As of December 31, 2004 and 2005, the Company had recorded short-term risk management assets of $4 million and $28 million, respectively, and short-term risk management liabilities of $5 million and $25 million, respectively, included in other current assets and other current liabilities, respectively.

A portion of CenterPoint Energy Services, Inc.'s (CES) activities include entering into transactions for the physical purchase, transportation and sale of natural gas at different locations (physical contracts). CES attempts to mitigate basis risk associated with these activities by entering into financial derivative contracts (financial contracts or financial basis swaps) to address market price volatility between the purchase and sale delivery points that can occur over the term of the physical contracts. The underlying physical contracts are accounted for on an accrual basis with all associated earnings not recognized until the time of actual physical delivery. The timing of the earnings impacts for the financial contracts differs from the physical contracts because the financial contracts meet the definition of a derivative under SFAS No. 133, and are recorded at fair value as of each reporting balance sheet date with changes in value reported through earnings. Changes in prices between the delivery points (basis spreads) can and do vary daily resulting in changes to the fair value of the financial contracts. However, the economic intent of the financial contracts is to fix the actual net difference in the natural gas pricing at the different locations for the associated physical purchase and sale contracts throughout the life of the physical contracts and thus, when combined with the physical contracts' terms, provide an expected fixed gross margin on the physical contracts that will ultimately be recognized in earnings at the time of actual delivery of the natural gas. As of December 31, 2005, the mark-to-market value of the financial contracts described above reflected an unrealized loss of $1 million; however, the underlying expected fixed gross margin associated with delivery under the physical contracts combined with the price risk management provided through the financial contracts is expected to offset the unrealized loss. As described above, over the term of these financial contracts, the quarterly reported mark-to-market changes in value may vary significantly and the associated unrealized gains and losses will be reflected in CES' earnings.

CES also sells physical gas and basis to its end-use customers who desire to lock in a future spread between a specific location and Henry Hub (NYMEX). As a result, CES incurs exposure to commodity basis risk related to these transactions, which it attempts to mitigate by buying offsetting financial basis swaps. Under SFAS No. 133, CES records at fair value and marks-to-market the financial basis swaps as of each reporting balance sheet date with changes in value reported through earnings. However, the associated physical sales contracts are accounted for using the accrual basis, whereby earnings impacts are not recognized until the time of actual physical delivery.

Although the timing of earnings recognition for the financial basis swaps differs from the physical contracts, the economic intent of the financial basis swaps is to fix the basis spread over the life of the physical contracts to an amount substantially the same as the portion of the basis spread pricing included in the physical contracts. In so doing, over the period that the financial basis swaps and related physical contracts are outstanding, actual cumulative earnings impacts for changes in the basis spread should be minimal, even though from a timing perspective there could be fluctuations in unrealized gains or losses associated with the changes in fair value recorded for the financial basis swaps. The cumulative earnings impact from the financial basis swaps recognized each reporting period is expected to be offset by the value realized when the related physical sales occur. As of December 31, 2005, the mark-to-market value of the financial basis swaps reflected an unrealized loss of $3 million.

(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, 2004 and 2005 (in millions):

	DECEMBER 31, 2004		DECEMBER 31, 2005	
	INVESTMENT GRADE(1)(2)	TOTAL	INVESTMENT GRADE(1)(2)	TOTAL
Energy marketers	$10	$17	$ 24	$ 25
Financial institutions ..	50	50	208	208
Other	1	1	--	2
Total	$61	$68	$232	$235

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(1) "Investment grade" is primarily determined using publicly available credit ratings along with the consideration of credit support (such as parent company guarantees) and collateral, which encompass cash and standby letters of credit.

(2) For unrated counterparties, the Company performs financial statement analysis, considering contractual rights and restrictions and collateral, to create a synthetic credit rating.

(c) GENERAL POLICY

CenterPoint Energy has established 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 Company'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.

6. LONG-TERM DEBT AND RECEIVABLES FACILITY

	DECEMBER 31, 2004		DECEMBER 31, 2005	
	LONG-TERM	CURRENT(1)	LONG-TERM	CURRENT(1)
	(IN MILLIONS)			
Long-term debt:				
Convertible subordinated debentures 6.00% due 2012	$ 69	$ 6	$ 63	$ 6
Senior notes 5.95% to 8.90% due 2006 to 2014	1,923	325	1,772	148
Junior subordinated debentures payable to affiliate 6.25% due 2026(2)	6	--	--	--
Other	--	36	--	--
Unamortized discount and premium(3)	3	--	3	--
Total long-term debt	$2,001	$367	$1,838	$154

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

(2) The junior subordinated debentures were issued to subsidiary trusts in connection with the issuance by those trusts of preferred securities. The trust preferred securities were deconsolidated effective December 31, 2003 pursuant to the adoption of FIN 46. This resulted in the junior subordinated debentures held by the trusts being reported as long-term debt.

(3) Debt acquired in business acquisitions is adjusted to fair market value as of the acquisition date. Included in long-term debt is additional unamortized premium related to fair value adjustments of long-term debt of $5 million at both December 31, 2004 and 2005, which is being amortized over the respective remaining term of the related long-term debt.

(a) LONG-TERM DEBT

In June 2005, the Company replaced its $250 million three-year revolving credit facility with a $400 million five-year revolving credit facility. Borrowings under this facility may be made at the London inter-bank offer rate (LIBOR) plus 55 basis points, including the facility fee, based on current credit ratings. An additional utilization fee of 10 basis points applies to borrowings whenever more than 50% of the facility is utilized. Changes in credit ratings could lower or raise the increment to LIBOR depending on whether ratings improved or were lowered. As of December 31, 2005, such credit facility was not utilized.

As of December 31, 2005, the Company was in compliance with various business and financial covenants contained in the credit facility. The Company's credit facility and its receivables facility limit the Company's debt as a percentage of its total capitalization to 65 percent.

Junior Subordinated Debentures (Trust Preferred Securities) In June 1996, a Delaware statutory business trust created by CERC Corp. (CERC Trust) issued $173 million aggregate amount of convertible preferred securities to the public. CERC Trust used the proceeds of the offering to purchase convertible junior subordinated debentures issued by CERC Corp. having an interest rate and maturity date that correspond to the distribution rate and mandatory redemption date of the convertible preferred securities. The convertible junior subordinated debentures represented CERC Trust's sole asset and its entire operations. The $6 million of outstanding junior subordinated debentures was included in long-term debt as of December 31, 2004. The convertible preferred securities and the related convertible junior subordinated debentures were redeemed on August 1, 2005.

Maturities. The Company's consolidated maturities of long-term debt and sinking fund requirements are $154 million in 2006, $7 million in 2007, $307 million in 2008, $6 million in 2009 and $6 million in 2010.

(b) RECEIVABLES FACILITY

In January 2006, the Company's $250 million receivables facility, which was temporarily increased to $375 million for the period from January 2006 to June 2006 to provide additional liquidity to the Company during the peak heating season of 2006, was extended to January 2007. As of December 31, 2005, the Company had $141 million of advances under its receivables facility.

Advances under the receivables facility averaged $100 million, $190 million and $166 million in 2003, 2004 and 2005, respectively. Sales of receivables were approximately $1.2 billion, $2.4 billion and $2.0 billion in 2003, 2004 and 2005, respectively.

7. INCOME TAXES

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

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
	(IN MILLIONS)		
Current			
Federal	$30	$86	$ 82
State	4	10	2
Total current	34	96	84
Deferred			
Federal	11	(3)	1
State	14	(6)	31
Total deferred	25	(9)	32
Income tax expense	$59	$87	$116

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

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
	(IN MILLIONS)		
Income before income taxes	$ 188	$ 231	$ 309
Federal statutory rate	35%	35%	35%
Income tax expense at statutory rate	66	81	108
Increase (decrease) in tax resulting from:			
State income taxes, net of valuation allowances and federal income tax benefit	12	2	22
Tax reserves	--	--	(13)
Changes in estimates for prior year items	(19)	--	--
Deferred tax asset write-off	--	4	--
Other, net	--	--	(1)
Total	(7)	6	8
Income tax expense	$ 59	$ 87	$ 116
Effective Rate	31.3%	37.5%	37.4%

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, 2004	December 31, 2005
	(IN MILLIONS)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 13	$ 19
Total current deferred tax assets	13	19
Non-current:		
Employee benefits	81	73
Operating and capital loss carryforwards	30	26
Deferred gas costs	68	59
Other	66	80
Total non-current deferred tax assets before valuation allowance	245	238
Valuation allowance	(20)	(21)
Total non-current deferred tax assets	225	217
Total deferred tax assets	238	236
Deferred tax liabilities:		
Current:		
Non-trading derivative liabilities, net	1	2
Total current deferred tax liabilities	1	2
Non-current:		
Depreciation	827	821
Regulatory liability	17	36
Other	22	23
Total non-current deferred tax liabilities	866	880
Total deferred tax liabilities	867	882
Accumulated deferred income taxes, net	$629	$646

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 $239 million of state net operating loss carryforwards. The losses are available to offset future state taxable income through the year 2024. Substantially all of the state loss carryforwards will expire between 2012 and 2020. A valuation allowance has been established against approximately 58% of the state net operating loss carryforwards.

The valuation allowance reflects a net decrease of $53 million in 2004 and an increase of $1 million in 2005. The net changes resulted from a reassessment of the Company's ability to use federal capital loss and state net operating loss carryforwards in 2004 and state net operating loss carryforwards, in 2005.

Tax Contingencies. The Company has established reserves for certain significant tax items including issues relating to prior acquisitions and dispositions of business operations and certain positions taken with respect to state tax filings. The total amount reserved for these tax items is approximately $32 million as of December 31, 2005.

8. COMMITMENTS AND CONTINGENCIES

(a) FUEL COMMITMENTS

Fuel 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 derivatives assets and liabilities in the Company's Consolidated Balance Sheets as of December 31, 2005 as these contracts meet the SFAS No. 133 exception to be classified as "normal purchases contracts" or do not meet the definition of a derivative. Minimum payment obligations for natural gas supply contracts are approximately $858 million in 2006, $375 million in 2007, $53 million in 2008, $4 million in 2009, $3 million in 2010 and $23 million 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):

2006	$14
2007	12
2008	11
2009	7
2010	4
2011 and beyond	22
Total	$70

Total rental expense for all operating leases was $28 million, $30 million and $32 million in 2003, 2004 and 2005, respectively.

(c) CAPITAL COMMITMENTS

In October 2005, CEGT signed a firm transportation agreement with XTO Energy 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 is in the process of filing applications for certificates with the FERC to build a 172 mile, 42-inch diameter pipeline, and related compression facilities at an estimated cost of $400 million. The final capacity of the pipeline will be between 960 MMcf per day and 1.24 billion cubic feet per day. CEGT expects to have firm contracts for the full capacity of the pipeline prior to its expected in service date in early 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, CEGT would construct a 67 mile extension from CEGT's Perryville hub to an interconnect with Texas Eastern Gas Transmission at Union Church, Mississippi.

(d) LEGAL MATTERS

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

In 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 of the Company's subsidiaries), limited the scope of the class of plaintiffs they purport to represent and eliminated previously asserted claims based on mismeasurement of the 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 suits are without merit. The Company does not expect the ultimate outcome 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., CenterPoint Energy Gas Transmission Company, 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 suit 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 Southern Gas Operations 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, CenterPoint Energy Gas Transmission Company, CenterPoint Energy Field Services, CenterPoint Energy Pipeline Services, Inc., Mississippi River Transmission Corp. 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. 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 regulatory authorities. The allegations in these cases are similar to those asserted in the City of Tyler proceeding described in Note 3(b). The Company and CenterPoint Energy do not expect the outcome of these matters to have a material impact on the financial condition, results of operations or cash flows of either the Company or CenterPoint Energy.

Pipeline Safety Compliance. Pursuant to an order from the Minnesota Office of Pipeline Safety, the Company 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, Minnesota Gas filed a request with the MPUC to recover the capitalized expenditures (approximately $39 million) and related expenses, together with a return on and of the capitalized portion through rates.

Minnesota Cold Weather Rule. In December 2004, the MPUC opened an investigation to determine whether Minnesota Gas' practices regarding restoring natural gas service during the period between October 15 and April 15 (Cold Weather Period) are in compliance with the MPUC's Cold Weather Rule (CWR), which governs disconnection and reconnection of customers during the Cold Weather Period. The Minnesota Office of the Attorney General (OAG) issued its report alleging Minnesota Gas has violated the CWR and recommended a $5 million penalty. Minnesota Gas and the OAG have reached an agreement on procedures to be followed for the current Cold Weather Period which began on October 15, 2005. 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 Minnesota Gas' conduct under the CWR was in violation of the law. Minnesota Gas is in settlement discussions regarding both the OAG's action and the action on behalf of the purported class. 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.

(e) 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, unspecified alleged personal injuries, alleged fear of cancer, alleged property damage or diminution of value of their property, and, in addition, seek damages for trespass, punitive, and exemplary damages. The Company does not expect the ultimate cost associated with resolving this matter to have a material impact on its financial condition, results of operations or cash flows.

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, 2005, the Company had accrued $14 million for remediation of these Minnesota sites. At December 31, 2005, 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, 2005, the Company has collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. The Company has been named as a defendant in two lawsuits filed in United States District Court, District of Maine and 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 court considering the other suit for contribution granted the Company's motion to dismiss on the grounds that it was not an "operator" of the site as had been alleged. The plaintiff in that case has filed an appeal of the court's dismissal of the Company. 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 cannot be 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.

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's management regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Company's management 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.

GUARANTEES

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 when separation occurred in September 2002, RRI had been unable to extinguish all obligations. To secure CenterPoint Energy and the Company against obligations under the remaining guarantees, 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 guarantees. The Company's current exposure under the remaining guarantees relates to its 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 in 2006 through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. As a result of changes in market conditions, the Company's potential exposure under that guaranty currently exceeds the security provided by RRI. The Company 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, and the Company and RRI are pursuing alternatives. RRI continues to meet its obligations under the transportation contracts.

9. ESTIMATED FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair values of cash and cash equivalents, investments in debt and equity securities classified as "available-for-sale" and "trading" in accordance with SFAS No. 115, and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair values of non-trading derivative assets and liabilities are equivalent to their carrying amounts in the Consolidated Balance Sheets at December 31, 2004 and 2005 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, 2004		DECEMBER 31, 2005	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Financial liabilities:				
Long-term debt	$2,368	$2,659	$1,992	$2,182

10. UNAUDITED QUARTERLY INFORMATION

Summarized quarterly financial data is as follows:

	YEAR ENDED DECEMBER 31, 2004			
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN MILLIONS)			
Revenues....................	$2,070	$1,217	$1,117	$2,068
Operating income............	160	64	32	137
Net income (loss)...........	74	11	(2)	61

	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

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, Pipelines and Field Services (formerly Pipelines and Gathering) 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. The Company reorganized the oversight of its Natural Gas Distribution business segment and, as a result, beginning in the fourth quarter of 2005, the Company established a new reportable business segment, Competitive Natural Gas Sales and Services. 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. Pipelines and Field Services includes the interstate natural gas pipeline operations and the natural gas gathering and pipeline services businesses. Other Operations consists primarily of other corporate operations which support all of the Company's business operations. All prior period segment information has been reclassified to conform to the 2005 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:

	NATURAL GAS DISTRIBUTION	COMPETITIVE NATURAL GAS SALES AND SERVICES	PIPELINES AND FIELD SERVICES	OTHER OPERATIONS	RECONCILING ELIMINATIONS	CONSOLIDATED
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2003:						
Revenues from external customers	$3,389	$2,017	$ 244	$ --	$ --	$5,650
Intersegment revenues	--	215	163	9	(387)	--
Depreciation and amortization	135	1	40	--	--	176
Operating income (loss)	157	45	158	(1)	--	359
Total assets	4,031	825	2,519	388	(910)	6,853
Expenditures for long-lived assets ..	198	1	66	--	--	265
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2004:						
Revenues from external customers	$3,577	$2,593	$ 306	$ (4)	$ --	$6,472
Intersegment revenues	2	255	145	5	(407)	--
Depreciation and amortization	141	2	44	--	--	187
Operating income (loss)	178	44	180	(9)	--	393
Total assets	4,083	964	2,637	792	(1,009)	7,467
Expenditures for long-lived assets ..	196	1	73	(1)	--	269
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2005:						
Revenues from external customers	$3,837	$3,884	$ 346	$ 3	$ --	$8,070
Intersegment revenues	9	245	147	7	(408)	--
Depreciation and amortization	152	2	45	(1)	--	198
Operating income (loss)	175	60	235	(6)	--	464
Total assets	4,612	1,849	2,968	743	(1,871)	8,301
Expenditures for long-lived assets ..	249	12	156	--	--	417

	YEAR ENDED DECEMBER 31,		
	2003	2004	2005
	(IN MILLIONS)		
Revenues by Products and Services:			
Retail gas sales..........................	$3,954	$4,239	$4,871
Wholesale gas sales.......................	1,064	1,526	2,410
Gas transport.............................	537	613	684
Energy products and services..............	95	94	105
Total.................................	$5,650	$6,472	$8,070

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, 2005 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.

In December 2005, the Company determined that, during 2004 and 2005, certain transactions involving purchases and sales of natural gas among divisions within its Natural Gas Distribution and Competitive Natural Gas Sales and Services segments were not properly eliminated in the consolidated financial statements. Consequently, revenues and natural gas expenses during the year ended December 31, 2004 were each overstated by approximately $511 million and during the nine months ended September 30, 2005 were each overstated by approximately $402 million. Management concluded that a restatement of the 2004 consolidated financial statements and the 2005 interim consolidated financial statements was necessary to correct this error. In connection with the discovery of the error described above and the conclusion that the Company had a material weakness in its internal control over financial reporting related to ineffective controls over the process of eliminating certain interdivision purchases and sales of natural gas within its Natural Gas Distribution and Competitive Natural Gas Sales and Services segments in the consolidation process, the Company improved procedures related to the recording and reporting of purchases and sales of natural gas during the three months ended December 31, 2005, including increased review and approval controls by senior financial personnel over the personnel that prepare the accruals and enhanced analysis of the recorded activity, including ensuring that intercompany activity is properly eliminated in consolidation. Management believes these changes remediated the material weakness in internal control over financial reporting referenced above as of December 31, 2005.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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

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, 2004 and 2005 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,	
	2004	2005
Audit fees	$840,408	$ 967,192
Audit-related fees	79,075	107,050
Total audit and audit-related fees	919,483	1,074,242
Tax fees	--	--
All other fees	--	--
Total fees	$919,483	$1,074,242

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.

Report of Independent Registered Public Accounting Firm.................... 30
Statements of Consolidated Income for the Three Years Ended December 31, 2005.................................... 31
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2005.................................... 32
Consolidated Balance Sheets at December 31, 2004 and 2005................. 33
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2005.................................... 34
Statements of Consolidated Stockholder's Equity for the Three Years Ended December 31, 2005..................................... 35
Notes to Consolidated Financial Statements................................ 36

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2005.

Report of Independent Registered Public Accounting Firm.................... 61
II-- Qualifying Valuation Accounts....................................... 62

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 64.

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, 2004 and 2005, and for each of the three years in the period ended December 31, 2005, and have issued our report thereon dated March 24, 2006 (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); 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 24, 2006

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, 2005

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, 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
Year Ended December 31, 2003:					
Accumulated provisions:					
Uncollectible accounts receivable.......	19	24	--	15	28
Deferred tax asset valuation allowance..	83	(10)	--	--	73

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(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.

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 24th day of March, 2006.

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 24, 2006.

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)

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	33-11329	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	33-54526	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 December 1, 1986, between NorAm and Citibank, N.A., as Trustee	NorAm's Form 10-K for the year ended December 31, 1986	1-13265	4.14
4(a)(2)	--	First Supplemental Indenture to Exhibit 4(a)(1) dated as of September 30, 1988	Form 10-K for the year ended December 31, 1997	1-3187	4(a)(2)
4(a)(3)	--	Second Supplemental Indenture to Exhibit 4(a)(1) dated as of November 15, 1989	Form 10-K for the year ended December 31, 1997	1-3187	4(a)(3)
4(a)(4)	--	Third 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(a)(4)
4(b)(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(b)(2)	--	Supplemental Indenture to Exhibit 4(b)(1) dated as of August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	4(b)(2)
4(c)(1)	--	Form of Indenture between NorAm and The Bank of New York as Trustee	NorAm's Registration Statement on Form S-3	33-64001	4.8

EXHIBIT NUMBER		DESCRIPTION	REPORT OR REGISTRATION STATEMENT	SEC FILE OR REGISTRATION NUMBER	EXHIBIT REFERENCE
4(c)(2)	--	Form of First Supplemental Indenture to Exhibit 4(c)(1)	NorAm's Form 8-K dated June 10, 1996	1-13265	4.01
4(c)(3)	--	Second Supplemental Indenture to Exhibit 4(c)(1) dated as of August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	4(d)(3)
4(d)	--	Indenture, dated as of December 1, 1997, between RERC Corp. and Chase Bank of Texas, National Association	Registration Statement on Form S-3	333-41017	4.1
4(e)(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(e)(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(e)(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(e)(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(e)(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(e)(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(e)(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(e)(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(e)(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(f)	--	$400,000,000 Credit Agreement, dated as of June 30, 2005, among CERC Corp., as borrower, and the Initial Lenders named therein, as Initial Lenders named therein, as Initial Lenders	CNP's Form 8-K dated June 29, 2005	1-31447	4.1

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 RATIO OF EARNINGS TO FIXED CHARGES
(MILLIONS OF DOLLARS)

	YEAR ENDED DECEMBER 31,				
	2001	2002	2003	2004	2005
Net income	$ 67	$ 120	$ 129	$ 144	$ 193
Income taxes	58	88	59	87	116
Capitalized interest	--	(1)	(1)	(2)	(1)
	125	207	187	229	308
Fixed charges, as defined:					
Interest expense	155	154	179	178	176
Capitalized interest	--	1	1	2	1
Interest component of rentals charged to operating expense	11	10	9	10	11
Total fixed charges	166	165	189	190	188
Earnings, as defined	$ 291	$ 372	$ 376	$ 419	$ 496
Ratio of earnings to fixed charges	1.76	2.25	1.99	2.20	2.64

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-128187 on Form S-3 of our reports relating to i) the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries dated March 24, 2006 (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), and ii) the consolidated financial statement schedule dated March 24, 2006, appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2005.

DELOITTE & TOUCHE LLP

Houston, Texas

March 24, 2006

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 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 24, 2006

/s/ David M. McClanahan

David M. McClanahan
Chairman, 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 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 24, 2006

/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, 2005 (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, that, to the best of my knowledge:

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
Chairman, President and
Chief Executive Officer
March 24, 2006

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, 2005 (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, that, to the best of my knowledge:

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 24, 2006